ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1

Question(s):

Following publication of the Notice of Application, the Ontario Energy Board (OEB) received several letters of comment. Sections 2.1.6 of the Filing Requirements state that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment.

Please file a response to the matters raised in the letters of comment that were also copied to Enbridge Gas Inc. (Enbridge Gas). Going forward, please ensure that responses to any matters raised in subsequent comments or letters that the applicant receives are filed in this proceeding. Please ensure that name and contact information is redacted for public filings. All responses must be filed before the argument (submission) phase of this proceeding.

Response:

Please see Attachment 1 for Enbridge Gas's response to the matters raised within the letters of comment.

ENBRIDGE GAS RESPONSE TO EB-2022-0200 LETTERS OF COMMENT

On Oct. 31, 2022 Enbridge Gas filed an Application with the Ontario Energy Board (OEB) to initiate a regulatory process called Rebasing. This process will determine the fair and reasonable regulated distribution, transmission and storage rates that Enbridge Gas will charge customers in 2024 to recover the costs of serving them safely and reliably and the opportunity to earn a return over a 5-year period.

To determine the rates we will charge customers for the following four years from 2025 to 2028, we are proposing an incentive regulation structure, which uses a formula that includes such items as inflation. This incentive regulation structure is very similar to the one used to set our rates from 2019 to 2023 and is the rate-setting mechanism prescribed by the OEB.

This is the first Rebasing Application we have submitted to the OEB as an integrated utility. It reflects the effects of utility integration, service and rate harmonization, and investments needed to support continued safe and reliable service for customers.

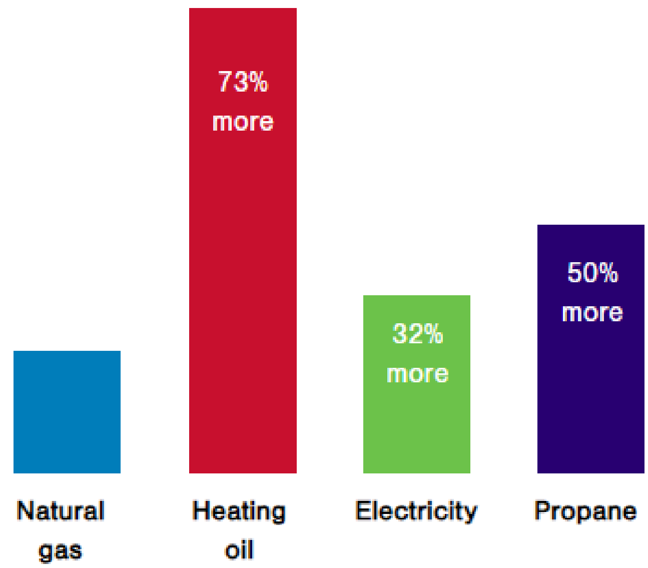
The OEB has a process to scrutinize our application and supporting evidence, which includes an opportunity for parties to file letters of comment. The OEB received over 300 letters of comment. Many of the letters asked the OEB not to approve a rate increase. Among the comments:

- Customers are financially strained and cannot manage further increases in their household bills.
- As there have been other Enbridge Gas bill increases over the past few years, there should be no further increases.
- Enbridge Gas is a monopoly, and our parent company, Enbridge Inc., is profitable.
- Concerns about the fairness of the rate harmonization plan and the information provided in the evidence accompanying the application.

This reply provides Enbridge Gas's response to the concerns raised.

Natural Gas and Affordability

Enbridge Gas passes on the cost of natural gas to its customers with no mark-up. Depending on market conditions, the cost of natural gas fluctuates. Within the last year natural gas prices have risen because of an increase in demand in North America after the COVID-19 shutdowns, and supply concerns caused by geopolitical uncertainty. Using data from the first quarter of 2023, the chart below shows natural gas continues to be the most cost-effective energy solution for homes and business, and costs significantly less than heating your home or business with electricity, oil or propane. Visit Natural Gas Prices Explained | Enbridge Gas for more information.



Our customers can save even more on their energy bills by improving the energy efficiency of their homes or businesses. Enbridge Gas provides a range of tools and education to give consumers and businesses the ability to manage their energy use. Visit Rebates & Energy Conservation | Enbridge Gas for more information.

We understand that energy affordability is a priority for our customers and we are committed to helping them manage their gas bills. Information on our customer support programs can be found at: Having Payment Difficulties | Enbridge Gas. Low-income customers having trouble paying their bill may qualify for emergency relief through the Low-income Energy Assistance Program. The program provides emergency relief with financial grants of up to $1,000 a calendar year. Customers can visit the United Way Simcoe Muskoka website for qualification information.

The Role of Enbridge Gas and the OEB

Natural gas distributors such as Enbridge Gas make significant investments to serve customers. Examples of the facilities we build, maintain and operate to serve customers are pipelines, storage facilities and compression stations. In Ontario, natural gas distributors such as Enbridge Gas are regulated by the OEB, the provincial energy regulator. One of the OEB's roles is to carefully review rate change applications, such as this 2024 rate application. While Enbridge Gas is an Enbridge Inc. company, only

Enbridge Gas's rates are subject to OEB jurisdiction. Additionally, we follow rules established by the OEB that govern our interactions with our parent company.

Customer Engagement

Customers are at the heart of our Application. We undertook extensive engagement with our customers, talking to more than 12,000 of them in 2021 and early 2022. They told us their priorities are energy affordability, reliability, and minimizing environmental impacts. This feedback is integrated into our business planning process.

Reflecting what customers told the utility is important to us. The proposed rates in this application will support a system that can continue to meet their needs safely and reliably in a cost-effective way, while at the same time helping them prudently prepare for the energy transition that is underway in the communities where they live, driven by existing and planned federal and provincial policies. A strong majority of customers themselves say they are willing to invest in the long-term health of the system, as well as low-carbon options and solutions to reduce impacts on the environment, through reasonable rate increases.

Savings and Cost Pressures

Customers are benefitting from the integration of Enbridge Gas Distribution and Union Gas. Despite the challenges of the global pandemic and with only five years to plan and carry out amalgamation initiatives, we will be passing $86 million in annual integration savings on to customers beginning in 2024. When you add in productivity initiatives, customers will benefit from more than $121 million in savings a year. This is offsetting the rising costs of operating our business and moderates the rate increases we believe are necessary to continue delivering safe and reliable service to our customers in 2024.

Harmonization

Since we began the process of integrating into one utility in 2019, many systems and services have been harmonized for a consistent and simplified customer experience. To further reflect the operations and services of a single utility, we are proposing to further align and simplify our rates and customer services, and to phase in changes to allow time to implement system changes and inform customers.

We are proposing to harmonize our three rate zones (EGD, Union North and Union South) into one rate zone and establish new harmonized rate classes to be implemented for general service customers in 2025 and for contract rate customers in 2026.

Harmonizing rate zones and rate classes will allow us to align, simplify and enhance rates and services to meet customer needs. It will give us the ability to treat customers across Ontario similarly, applying the same rates for the same service to customers in the same rate class, regardless of where they are. In addition, our customer communications, regulatory applications and reporting will be simplified.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ginoogaming First Nation (GFN)

Interrogatory

Reference:

Exhibit 1, Tab 1, Schedule 2, p. 5, para 17

Preamble:

EGI notes that that persons affected by the Application include the "customers resident or located in the municipalities, police villages and **First Nations reserves served by the Applicant**, together with those to whom the Applicant sells gas, or on whose behalf the Applicant distributes, transmits or stores natural gas." (emphasis added)

Question(s):

a) Please file any and all analysis EGI has performed in connection with how the Application will, or is anticipated to, affect the First Nations rights-holding communities:

   i. that EGI serves;
   ii. to which EGI sells gas; and
   iii. on whose behalf EGI distributes, transmits, or stores gas.

   If EGI has not undertaken any such analysis, please explain why no such analysis has been undertaken, in light of the statement in paragraph 17.

Response:

a) The Application involves among other things, a Decision for the approval of rates effective January 1, 2024, for all customers that Enbridge Gas serves. In Enbridge Gas's view, First Nations reserves served by Enbridge Gas will be affected by the Application in a similar manner to other organizations, individuals, and customers Enbridge Gas serves.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ginoogaming First Nation (GFN)

Interrogatory

Reference:

Exhibit 1, Tab 1, Schedule 2, p. 5, para 17
Enbridge Inc.'s Indigenous Peoples Policy[1] ("**IPP**")

Preamble:

Enbridge Inc.'s IPP provides that Enbridge will engage with "forthright and sincere consultation with Indigenous Peoples about Enbridge's projects **and operations** through processes that seek to achieve early and meaningful engagement". Enbridge also notes that the commitments made in the IPP are "a shared responsibility involving Enbridge **and its affiliates**, employees and contractors" and that they "will conduct business in a manner that reflects" the principles provided in the IPP.

Question(s):

a) Please place Enbridge Inc.'s IPP on the record in this proceeding.

b) Please indicate whether EGI adhered to the principles articulated in the IPP as it developed the Application. If yes, please discuss how EGI upheld the commitments in the IPP with respect to the Application. If no, please explain why not.

c) Please provide all internal policy frameworks and guidance other than the IPP that EGI relied on to guide its engagement and relationship with First Nations and how this informed EGI's development of the Application.

Response:

a) Please see response at Exhibit I.1.6-Three Fires-1 part a).

b) Please see response at Exhibit I.1.6-Three Fires-1 part b).

[1] Enbridge Inc., *Indigenous Peoples Policy*, (August 2022), available online: https://www.enbridge.com/-/media/Enb/Documents/About-Us/indigenous_peoples_policy_final.pdf?rev=839a88ff9657465aa0b039d139d98166&hash=B98D08567204E4E2468FA166EF955E88>.

c) The IPP is the primary policy framework that guides Enbridge Inc.'s (Enbridge) engagement with First Nations. In addition, the Indigenous Reconciliation Action Plan, which is provided in response at Exhibit I.1.6.Three Fires-1 part a), serves as a corporate roadmap for Enbridge's continued journey towards truth and reconciliation. Enbridge Gas's engagement is also informed by external requirements such as the OEB Environmental Guidelines for Hydrocarbon Pipelines and Facilities in Ontario as well as guidance provided by legal decisions. For the purposes of this application, consistent with its frameworks and external guidance, Enbridge Gas has not undertaken a consultation program commensurate with what would be undertaken in relation to an application for facilities that may have a potential impact on Aboriginal and treaty rights. Nevertheless, the overarching principles in the IPP, including the recognition of the importance of reconciliation between Indigenous peoples and broader society, will continue to guide Enbridge Gas's interactions with Indigenous communities and peoples.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Preamble:

In support of its application and proposed revenue requirement recovery from customers, EGI has retained, and presented evidence from, a number of external experts.

Question(s):

a) Please provide EGI's best estimate of the total cost for all of the external experts retained by EGI in support of its application.

b) Please provide the total OEB proceeding related regulatory costs included in EGI's 2024 test year revenue requirement.

Response:

a) Please see response at Exhibit I.1.2-CCC-3.

b) Total OEB and intervenor proceeding related regulatory costs included in Enbridge Gas's 2024 Test Year are $11.4 million.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1.1

Question(s):

Please update the following tables and figures for 2022 year-end actuals:

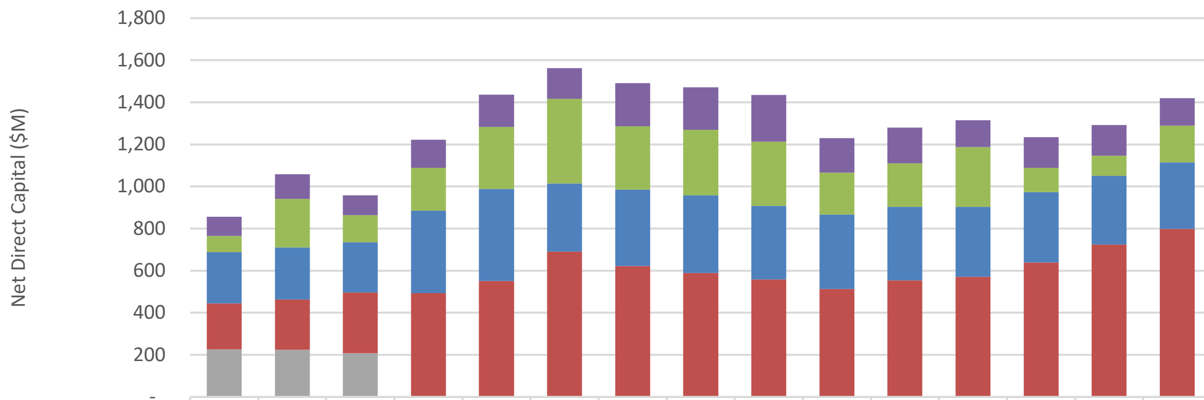
a) [2-2-1, p.3] Table 1
b) [2-5-3, p.13] Table 6
c) [2-6-1, p.36] Figure 6
d) [3-1-1] Table 2
e) [3-2-1] Table 1
f) [3-2-1] Attachment 1
g) [4-4-2] Table 1-Table 12
h) [4-4-3] Table 1-Table 3

Response:

a-b) Please see response at Exhibit I.2.1-CCC-36, Attachment 1.

c) Please see updated Figure 6.

Figure 6: Utility Capital Expenditures including 2022 Actual



	2018A	2019A	2020A	2021A	2022A	2023F	2024F	2025F	2026F	2027F	2028F	2029F	2030F	2031F	2032F
General Plant	91	117	93	134	155	145	205	202	222	163	169	128	146	146	131
System Service	78	231	130	205	294	403	301	311	306	200	206	284	116	95	175
System Access	242	246	238	391	437	323	362	369	349	353	350	332	335	327	315
System Renewal	220	239	287	494	552	691	623	589	559	514	554	571	639	724	799
Overhead	226	225	209	-	-	-	-	-	-	-	-	-	-	-	-
Grand Total	857	1,058	958	1,223	1,437	1,562	1,491	1,471	1,436	1,229	1,279	1,315	1,235	1,292	1,420

Note: Overheads are included in the Investment Categories starting in 2021.

d-f) Please see response at Exhibit I.3.3-STAFF-95, Attachment 1.

g) Attachment 1 reflects 2022 actuals in Tables 1-12 of Exhibit 4, Tab 4, Schedule 2, updated March 8, 2023.

h) Attachment 2 reflects 2022 actuals in Tables 1-3 of Exhibit 4, Tab 4, Schedule 3, updated March 8, 2023.

Table 1
Utility O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Business Development & Regulatory	EGI	43	37	28	33	35	40	47
2	Customer Care	EGI	153	131	118	117	120	124	135
3	Distribution Operations	EGI	275	281	268	274	317	331	338
4	Energy Services	EGI	21	17	14	16	16	19	18
5	Engineering & STO	EGI	113	110	96	111	140	158	155
6	Central Functions	EGI	231	237	245	280	363	353	377
7	BU Benefits	EGI	144	158	148	143	118	112	111
8	Overhead Capitalization	EGI	(227)	(237)	(224)	(234)	(270)	(301)	(310)
9	Utility O&M excl. Integration and DSM	EGI	753	734	692	739	840	835	871
10	Integration-Related Costs	EGI	0	52	124	50	31	20	0
11	DSM	EGI	130	129	132	132	132	167	175
12	Utility O&M	EGI	883	915	948	921	1,003	1,022	1,046

Note:
(1) 2018 reflects combined EGD and Union actuals.

Table 2
Integration Synergies and Productivity Savings

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)
1	Integration Synergies	EGI	32.3	52.4	71.2	85.8	86.0	86.0
2	Productivity Savings	EGI	8.2	18.6	18.6	17.6	31.0	35.2
3	Total	EGI	40.5	70.9	89.8	103.4	117.0	121.2

Table 3
Business Development & Regulatory O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Salaries & Wages	EGI	17.1	13.5	11.4	11.1	13.1	13.7	18.0
2	Contract Services	EGI	20.4	16.5	14.8	16.1	18.3	19.6	22.6
3	Sponsorships & Memberships	EGI	5.3	5.0	1.1	4.2	1.8	3.9	4.1
4	Other O&M	EGI	(0.2)	1.7	0.8	1.3	1.7	2.4	2.5
5	Total	EGI	42.6	36.7	28.1	32.7	34.9	39.6	47.2

Notes:

(1) 2018 reflects combined EGD and Union actuals.

(2) 2018 Energy Conservation amount represents EGD's share (50%) of the net recovery generated by providing conservation and demand management (CDM) activities. Ratepayer share (50%) was cleared through the Electric Program Earnings Sharing Deferral Account (EPESDA).

Table 4
Customer Care O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Salaries & Wages	EGI	26.6	24.5	22.1	23.7	23.4	25.6	27.1
2	Contract Services	EGI	106.0	93.3	81.6	82.8	77.0	79.4	80.9
3	Bad Debt	EGI	10.6	9.0	10.7	13.2	15.4	17.5	21.5
4	Other O&M	EGI	9.8	3.9	3.2	(3.1)	4.7	1.4	5.6
5	Total	EGI	153.0	130.7	117.6	116.6	120.5	123.9	135.1

Note:
(1) 2018 reflects combined EGD and Union actuals.

Table 5
Distribution Operations O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Salaries & Wages	EGI	148.8	146.3	131.4	134.0	148.2	153.0	158.9
2	Contract Services	EGI	89.5	100.0	94.1	95.9	122.5	117.3	118.5
3	Materials & Supplies	EGI	16.7	17.5	17.9	17.9	18.8	16.3	16.6
4	Fleet & Fuel	EGI	16.7	16.3	14.0	19.2	19.9	22.4	22.7
5	Other O&M	EGI	(0.9)	(3.9)	6.4	2.8	4.4	15.9	15.3
6	Major Projects	EGI	4.6	4.4	4.0	3.8	2.7	6.0	6.1
7	Total	EGI	275.4	280.6	267.8	273.6	316.5	330.9	338.1

Notes:
(1) 2018 reflects combined EGD and Union actuals.
(2) Other O&M credit position in 2018 and 2019 is due to third party plant damage recoveries.

Table 6
Energy Services O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Salaries & Wages	EGI	17.7	14.8	11.9	12.5	13.6	14.9	15.9
2	Contract Services	EGI	2.0	1.5	1.4	1.7	0.6	1.3	1.3
4	Other O&M	EGI	1.2	1.1	1.0	1.4	1.9	2.5	0.7
5	Total	EGI	20.9	17.4	14.3	15.6	16.1	18.7	17.9

Note:
(1) 2018 reflects combined EGD and Union actuals.

Table 7
Engineering & STO O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Salaries & Wages	EGI	74.3	69.8	63.8	64.6	67.1	74.9	79.4
2	Contract Services	EGI	40.6	36.5	29.4	35.8	56.6	63.3	61.5
3	Materials & Supplies	EGI	9.4	10.2	8.5	10.8	9.5	10.9	11.1
4	Rents & Leases	EGI	8.7	8.8	9.1	10.3	11.2	12.3	12.5
5	Other O&M	EGI	(20.0)	(15.7)	(15.2)	(10.4)	(4.6)	(3.4)	(9.6)
6	Total	EGI	113.0	109.6	95.6	111.1	139.8	158.0	154.9

Note:
(1) 2018 reflects combined EGD and Union actuals.

Table 8
Central Functions O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual (1)	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Central Functions	EGI	230.5	237.3	244.6	279.8	363.5	352.9	377.1

Note:
(1) 2018 reflects combined EGD and Union actuals.

Table 9
Business Unit Benefits

Line No.	Particulars ($ millions)	Utility	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	BU Benefits	EGI	144.1	158.4	148.4	143.3	118.0	111.8	111.1

Note:
(1) 2018 reflects combined EGD and Union actuals.

Table 10
Integration-Related Costs

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	Total
			(a)	(b)	(c)	(d)	(e)	(f)
1	Integration Costs	EGI	10.2	46.4	49.8	30.6	19.5	156.5
2	Integration Severance	EGI	41.5	77.7				119.1
3	Total Integration-Related Costs	EGI	51.7	124.0	49.8	30.6	19.5	275.6

Table 11
Overhead Capitalization

Line No.	Particulars ($ millions)	Utility	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Overhead Capitalization	EGI	(226.5)	(237.2)	(224.3)	(234.2)	(269.7)	(301.1)	(310.4)

Note:
(1) 2018 reflects combined EGD and Union actuals.

Table 12
Utility O&M

Line No.	Particulars ($ millions)	Utility	2022 Actual	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)
1	Business Development & Regulatory	EGI	35	40	47
2	Customer Care	EGI	120	124	135
3	Distribution Operations	EGI	317	331	338
4	Energy Services	EGI	16	19	18
5	Engineering & STO	EGI	140	158	155
6	Central Functions	EGI	363	353	377
7	BU Benefits	EGI	118	112	111
8	Overhead Capitalization	EGI	(270)	(301)	(310)
9	Utility O&M excl. Integration and DSM	EGI	840	835	871
10	Integration-Related Costs	EGI	31	20	0
11	DSM	EGI	132	167	175
12	Utility O&M	EGI	1,003	1,022	1,046

Table 1
Employees - Full Time Equivalents

Line No.	Particulars ($ millions)	Utility	EGD - Business Unit (1)	Union - Business Unit (1)	EGI - Business Unit (1)(2)	EGI - Central Functions (1)(3)
			(a)	(b)	(c)	(d)
1	2013 Actual	EGD/Union	2,206	2,182		
2	2014 Actual	EGD/Union	2,194	2,220		
3	2015 Actual	EGD/Union	2,130	2,253		
4	2016 Actual	EGD/Union	2,063	2,272		
5	2017 Actual	EGD/Union	1,934	2,239		
6	2018 Actual	EGD/Union	1,639	1,810		691
7	2019 Actual	EGI			3,229	569
8	2020 Actual	EGI			2,946	526
9	2021 Actual	EGI			3,013	503
10	2022 Actual	EGI			3,182	471
11	2023 Bridge Year	EGI			3,507	546
12	2024 Test Year	EGI			3,470	546

Notes:

(1) Number of Full-time and Part-time FTEs, excludes employees on leave and contractors as at December 31st of each year.

(2) Business Unit FTEs are EGI employees that provide core services to the utility.

(3) Central Functions FTEs are EGI employees that provide shared services to the utility. Their costs have been excluded from EGI Compensation amounts starting in 2018 following the Enbridge-Spectra merger as costs are allocated through the Central Functions Cost Allocation Methodology.

Table 2
Compensation

Line No.	Particulars ($ millions)	Utility	Salaries & Wages (1)	Total Benefits and Incentive Pay (2)	Total Compensation (3)
			(a)	(b)	(c)
1	2013 OEB-Approved	EGD/Union	377	171	548
2	2013 Actual	EGD/Union	354	203	557
3	2014 Actual	EGD/Union	370	190	560
4	2015 Actual	EGD/Union	371	196	567
5	2016 Actual	EGD/Union	370	190	560
6	2017 Actual	EGD/Union	372	169	541
7	2018 Actual	EGD/Union	300	144	444
8	2019 Actual	EGI	286	158	444
9	2020 Actual	EGI	275	148	423
10	2021 Actual	EGI	279	143	422
11	2022 Actual	EGI	294	118	412
12	2023 Bridge Year	EGI	310	112	422
13	2024 Test Year	EGI	317	111	428

Notes:

(1) Salaries and wages include overtime.

(2) Benefits include pension, incentives, and other post-employment benefits costs.

(3) Costs for employees that are part of CFs have been excluded from EGI compensation amounts starting in 2018 following the Enbridge Spectra merger as costs are allocated through the Central Function Cost Allocation Methodology.

Table 3
CF Costs

Line No.	CF ($millions)	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Aviation	0	0	0	0	0	0	0
2	CDO	1.5	1.5	1.5	1.6	3.5	2.4	2.5
3	EAWM	0	0	0.2	0.6	1.6	1.8	1.9
4	Executive	0.6	0.6	0.6	0.6	0.8	1.1	1.1
5	Finance	30.1	25.2	25	28.4	32.8	35.9	36.7
6	REWS	26.3	26.1	30.4	26.7	24.6	28.1	28.7
7	HR	20.5	22.9	25.5	22.1	22.9	25.3	25.9
8	Legal	10.4	13.7	11	11	14.6	15	15.3
9	PAC	5	5.3	5.6	4.3	6.5	6.5	6.6
10	S&R	4.8	5.7	8.1	6.8	10.1	7.4	7.5
11	SCM	7.5	7.4	11.2	8.2	11.7	12	12.2
12	TIS	59.4	70.2	66	75	100	125.4	139.7
13	Benefits	34.1	27.2	26.6	57.1	103.6	64.8	66.1
14	Depreciation	20.4	20.9	21.2	22	21.6	20	25.6
15	Insurance	9.9	10.6	11.7	15.4	9.2	7.2	7.3
16	CF Costs	230.5	237.3	244.6	279.8	363.5	352.9	377.1

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-1-6

Question(s):

For each third-party report filed in the application, please i) provide a copy of the retainer agreement with the third-party, ii) confirm if Enbridge is relying on the evidence as expert evidence, iii) provide the names of the specific authors of the report.

Response:

i. Please see response at Exhibit I.1.2-CCC-3, Attachment 2 for third-party reports associated to Phase 1 of the Application.

ii. Confirmed. Enbridge Gas is relying on the evidence as expert evidence for third-party reports associated to Phase 1 of the Application.

iii. Please see response at Exhibit I.1.2-CCC-3, Attachment 1 for authors of third-party reports associated to Phase 1 of the Application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 2, Schedule 1, pp. 13 and 19; Exhibit 1, Tab 8, Schedule 1, Attachment 10, p. 77; Exhibit 1, Tab 10, Schedule 4, p. 16

Question(s):

The Government of Canada has committed to reducing greenhouse gas (GHG) emissions by 40% below 2005 levels by 2030 and the Government of Ontario has committed to reducing GHG emissions by 30% below 2005 levels by 2030.

Enbridge Gas states that energy transition poses a significant increase to the risks faced by natural gas utilities. Enbridge Gas considered alternatives to respond to these increasing risks, including changes to the expected service life of assets and changes to its deemed equity ratio to address increased business risk.

For each of the following categories of community and system expansion projects, please respond to the questions that follow: (i) Natural Gas Expansion Program (NGEP) funded expansion projects; (ii) non-NGEP funded expansion projects that require the use of Contributions in Aid of Construction (CIAC), System Expansion Surcharges (SES), Temporary Connection Surcharges (TCS) or Hourly Allocation Factors; and (iii) other expansion projects that do not require any of the funding sources mentioned in categories (i) and (ii).

a) Please provide the number of projects that will be constructed by the end of 2028 in each category.

b) Please provide the total capital costs across all projects for each category.

c) If available, please provide the average capital cost per residential customer across all projects in each category.

d) Please provide the average amortization period, in years, across all projects in each category.

e) Given Enbridge Gas's statements regarding stranded asset risk that it is facing and considering that federal and provincial commitments to reducing GHGs are likely nearer term than the amortization period for the projects in these categories, please explain further what Enbridge Gas has done or is considering doing to manage the risk of stranded assets in each category.

Response:

(i) Natural Gas Expansion Program (NGEP) funded expansion projects:

a-b) Please see response at Exhibit I.1.2-CCC-12 part d)

c) Please see Table 1 for the average cost per customer specific to Community Expansion Phase 2 projects.

Table 1

i) Community Expansion - Average Cost	2023F	2024F	2025F	2026F	2027F	2028F	Total
Community Expansion	13,981,689	24,408,757	27,388,718	11,240,506	7,029,908	7,343,532	91,393,110
Customer Adds	579	1,257	2,019	1,802	1,388	1,053	8,098
Average Cost CE	**24,148**	**19,418**	**13,565**	**6,238**	**5,065**	**6,974**	**11,286**

Table 1 sets out the capital spend that was known and included in the current Application.

(ii) Non-NGEP funded expansion projects that require the use of Contributions in Aid of Construction (CIAC), System Expansion Surcharges (SES), Temporary Connection Surcharges (TCS) or Hourly Allocation Factors:

a) As described in part a) response part iii) below, the customer connection forecast is determined using the approach described in Exhibit 2, Tab 6, Schedule 2, page 66 of 288, Section 5.1.4.3 Customer Connections Forecast. In this section, Enbridge Gas explains that a primary data source used in predicting growth is historical housing starts from the Canadian Mortgage and Housing Corporation. While this data is augmented with information originating from direct contact with builders, developers and municipalities, it is primarily built on a macro-economic view using historical data, accounting for future Energy Transition assumptions; therefore, project specific Profitability Indexes which would drive Contribution in Aid of Construction (CIAC), System Expansion Surcharges (SES), Temporary Connection Surcharges (TCS) or Hourly Allocation Factors (HAF), are not projected as part of this forecast for non-NGEP funded expansion projects. Furthermore, the market for attachments funded through the latter three of these mechanisms is still relatively new, and therefore Enbridge Gas has very little historical data upon which to build a future forecast at the project level. Although Enbridge Gas does not forecast number of projects, by type or at the aggregate level, based on a three year historical average, Enbridge Gas estimates 1100-1200 projects will be constructed as a total for all project types, and for the time period, listed within this question.

b) The total estimated project cost, based on a 3-year average, is approximately $48 million for the 2023 to 2028 forecast period.

c) Enbridge Gas is unable to provide information regarding the cost per residential customer specific to projects that include CIAC, SES, TCS and HAF. Please see the Table 2 for the average cost per customer for all customer types regardless of whether there is payment. Note that overheads are excluded from the Customer Connections capital in the calculation of average cost per customer.

Table 2

ii) Customer Connection - Average Cost	2023F	2024F	2025F	2026F	2027F	2028F	Total
Customer Connections	176,813,537	194,442,250	192,920,500	191,600,178	187,657,823	181,618,178	1,125,052,466
Customer Adds	41,519	40,712	39,744	38,821	37,523	35,961	234,280
Average Cost	**4,259**	**4,776**	**4,854**	**4,935**	**5,001**	**5,050**	**4,802**
***Average Cost of Total Customer Connections and TCS forecast. Forecast is not split out by sector or by TCS.							

(iii) Other expansion projects that do not require any of the funding sources mentioned in categories (i) and (ii):

a) Specific system expansion projects which are executed under Enbridge Gas's Customer Connections program and pass the financial test under E.B.O 188 are not discretely identified within the current capital plan at the project level. The customer connection forecast is determined using the approach described in Exhibit 2, Tab 6, Schedule 2, page 66 of 288, Section 5.1.4.3 Customer Connections Forecast. Required capital to fund the program is determined using this approach, and projects are identified at a regional level closer to and often during the year of construction. Although Enbridge Gas does not forecast number of projects, by type or at the aggregate level, based on a 3 year historical average, Enbridge Gas estimates 6000-7000 projects will be constructed as a total for all project types, and for the time period, listed within this question.

b) The total estimated project cost, based on a 3-year average, is approximately $420 million for the 2023 to 2028 forecast period. Please see Exhibit 2, Tab 6, Schedule 2, page 75 of 288, Table 5.1.10-1 under Customer Connections Additions for details on capital costs.

c) Please see part ii) c) above.

d) It is the Company's understanding that the amortization period mentioned in this question refers to the revenue horizon of different types of projects. The average revenue horizon for all types of projects mentioned in the question is 40 years.

e) Please see response at Exhibit I.1.10-STAFF-34 part a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 2, Schedule 1, pp. 13 and 19

Question(s):

The Government of Canada has committed to reducing GHG emissions by 40% below 2005 levels by 2030, and to net-zero emissions by 2050, and the Government of Ontario has committed to reducing GHG emissions by 30% below 2005 levels by 2030.

The forecast capital expenditure for the 2024 Test Year is $1,491.7 million and includes supporting the demand for customer and system growth.

a) Is Enbridge Gas planning to construct by 2028 any non-NGEP supported community expansion projects that will require the use of CIAC, SES, TCS or Hourly Allocation Factors? If so, how many, where are they located, and in what years might they go into service?

b) For any projects identified in part (a), please:

   i. Comment on their feasibility
   ii. Explain how Enbridge Gas is assessing electrification as an alternative to natural gas (whether conventional, renewable, or hydrogen blended natural gas)
   iii. Comment on (and quantify, if possible) their overall average capital cost per residential customer (i.e., do not provide an updated average capital cost per residential customer for each project)
   iv. Confirm that their amortization period is 40 years; if not, please explain
   v. Explain what Enbridge Gas is doing to manage the risk of stranded assets considering that federal and provincial commitments to reducing GHGs are nearer term than the amortization period for these projects.

c) Is Enbridge Gas planning to construct by 2028 any non-NGEP supported community expansion projects that will not require the use of CIAC, SES, TCS or Hourly Allocation Factors? If so, how many, where are they located, and in what years might they go into service?

d) For any projects identified in part (c), please:

i. Comment on their feasibility
ii. Explain how Enbridge Gas is assessing electrification as an alternative to natural gas (whether conventional, renewable, or hydrogen blended natural gas)
iii. Comment on (and quantify, if possible) their overall average capital cost per residential customer (i.e., do not provide an updated average capital cost per residential customer for each project)
iv. Confirm that their amortization period is 40 years; if not, please explain
v. Explain what Enbridge Gas is doing to manage the risk of stranded assets considering that federal and provincial commitments to reducing GHGs are nearer term than the amortization period for these projects.

Response:

a) Please see response at Exhibit I.1.2-STAFF-2 part ii) a).

b)
i. All project feasibilities aim to achieve a PI>=1. Please see response at Exhibit I.1.15-ED-82 part c).

ii. Enbridge Gas interprets this question to mean how has the Company included electrification trends in customer attachment forecasts. Please see Exhibit 1, Tab 10, Schedule 4 for a summary of the planning assumptions in the Rebasing Application.

iii. Please see response at Exhibit I.1.2-STAFF-2 part ii) c).

iv. Please see response at Exhibit I.1.2-STAFF-2 part d).

v. Please see response at Exhibit I.1.10-STAFF-34 part a).

c) Please see response at Exhibit I.1.2-STAFF-2 part iii) a).

d)
i. All project feasibilities aim to achieve a PI>=1. Please see response at Exhibit I.1.15-ED-82 part c).

ii. Please see b) ii) above.

iii. Please see response at Exhibit I.1.2-STAFF-2 part iii) c).

iv. Please see response at Exhibit I.1.2-STAFF-2 part d).

v. Please see response at Exhibit I.1.10-STAFF-34 part a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2

Question(s):

Please provide all materials presented to the EGI Board of Directors and Enbridge Inc.'s Board of Directors with respect to this Application.

Response:

Please see:

- Attachment 1 – 2024 Rebasing Application Update presentation, which was provided to the Enbridge Gas Board of Directors and Enbridge's Board of Directors.

- Attachment 2 – Rebasing and Incentive Rate Mechanism Update presentations, includes quarterly updates provided to Enbridge's Board of Directors.

Please also see response at Exhibit I.1.2-SEC-76 for the materials provided to Enbridge management with respect to the Application.

2024 Rebasing Application Update

Board of Directors
Oct. 25, 2022

2024 Rebasing Context

ENBRIDGE

- First Cost of Service application since 2013 for both legacy utilities
  - GDS was able to defer cost of service rates in 2019 as a result of amalgamation
  - Seeking re-based cost of service rates effective Jan. 1, 2024 and inflation adjusted rates for 2025 – 2028
  - Ratepayers expect to receive the benefits of amalgamation in 2024, including lower costs and customer service benefits
- Affordability concerns dominate Ontario political landscape
  - Gas bills are at an all time high due to the impact of carbon charges and elevated commodity prices, eroding competitive advantage to electricity
- Climate action views of regulators and intervenors inconsistent with significant investments in gas infrastructure
  - GDS released "pathways to net zero" report that models diversified and electrification pathways, showing former is more affordable, reliable and resilient
  - Investments in energy efficiency, RNG, hydrogen and CCUS and electricity needed

Ratepayer groups are seeking benefits from utility amalgamation, affordable energy and climate action

Major Themes: 2024 Cost of Service

ENBRIDGE

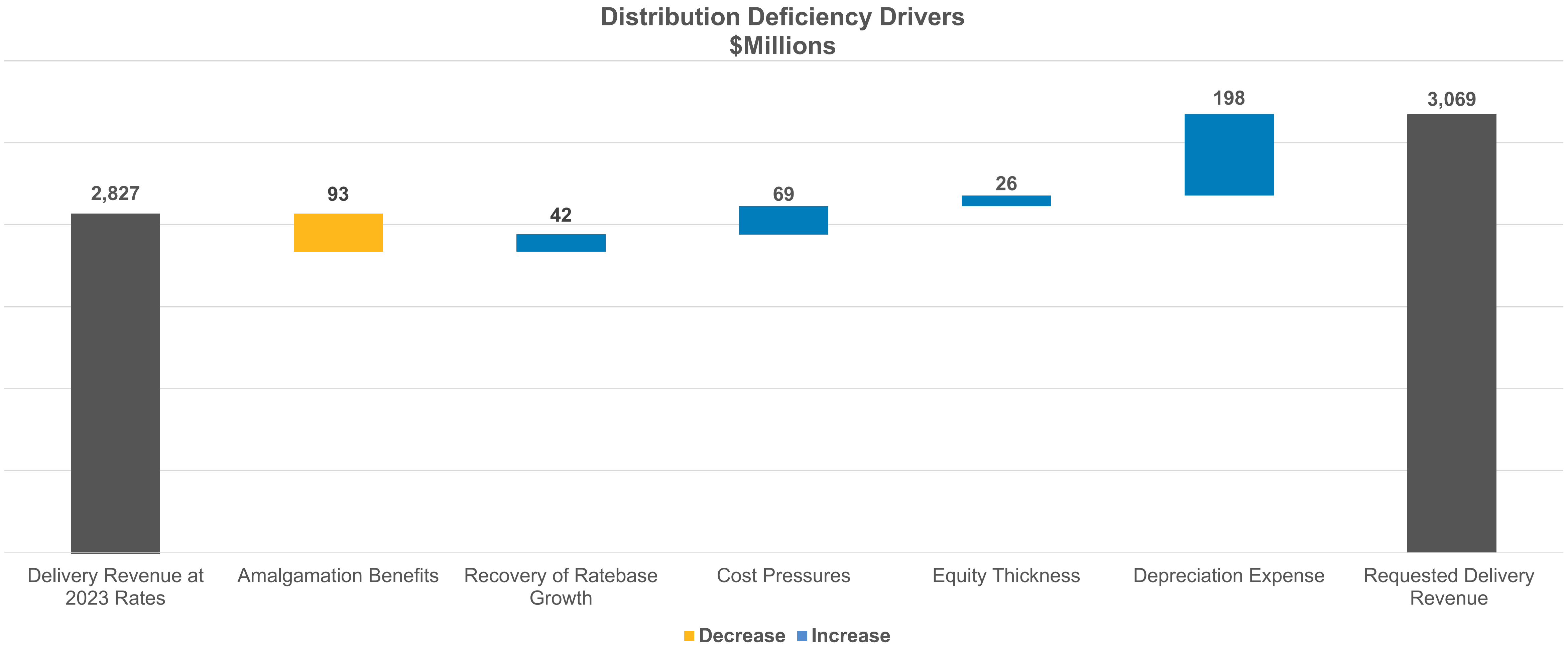
- Operations and Maintenance
  - Significant synergies during the deferred rebasing period offset by cost pressures due to inflation and increased safety, reliability and technology requirements
- Recovery of Capital Costs
  - Addition of depreciated cost of all capital additions from 2013 to 2023 and 2024 results in modest rate increase

- Equity Thickness
  - Energy transition has increased business risk since the 2013 capital structure determination
  - EGI at 36% equity has the lowest equity thickness of any comparable utility in North America
  - Proposal seeks 42% with a phased-in approach starting with 38% in 2024 to help mitigate impacts to rate-payers

- Depreciation Expense
  - Updated depreciation methodology and single depreciation rate for each combined asset account results in a significant increase in depreciation expense

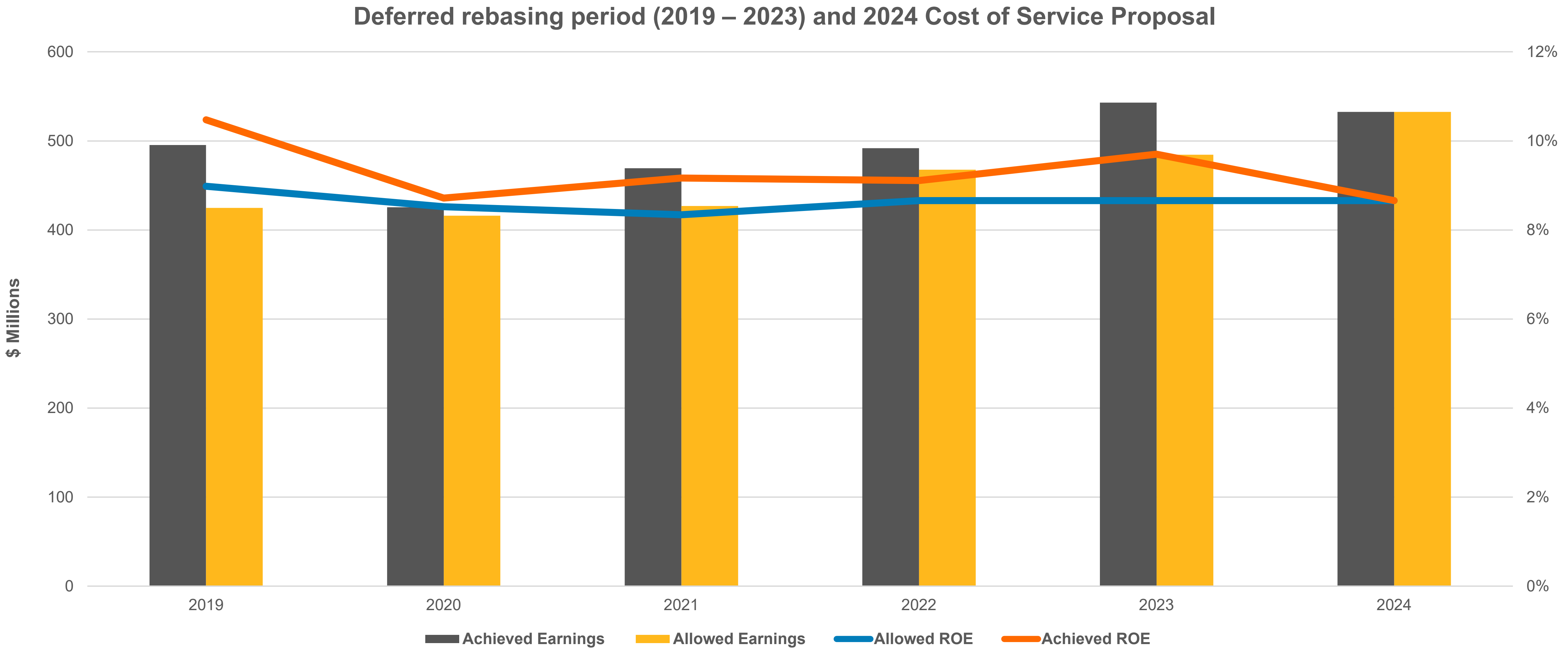
Rebasing proposal balances customer and shareholder needs

2024 Revenue Deficiency



8.6% increase in distribution revenue reflects a 4% average customer bill impact

Earnings 2019 – 2024



Deferred rebasing period achieved ROE ~70 bps above allowed

Major Themes: Incentive Ratemaking (2025 – 2028)

ENBRIDGE

- Rates will be set by using a Price Cap Formula calculated as (I - X) ± Y ± Z + ICM, where:
  - I = Weighted inflation factor, proposed 75:25 non labor inflation (GDP IPI) to labor (average hourly earnings)
  - X = productivity factor and stretch factor (1.35% “adder” to inflation proposed to reflect negative productivity)
  - Y = Costs not subject to Price Cap escalation (pass-through items such as gas costs, energy efficiency programs and specific costs afforded the passthrough treatment)
  - Z = costs associated with unforeseen events outside of management control (maintain existing $5.5M threshold)
  - ICM = Incremental Capital Module to seek funding for incremental capital projects that meet criteria of need, prudence and materiality and exceed the level supported by the formula
  - Earnings Sharing Mechanism, applicable if earnings exceed 150 basis points above allowed ROE, with 50/50 sharing between ratepayers and shareholders (same as current)

Independent consultant recommends rate increases exceeding inflation to reflect NA gas utility cost trends

Energy Transition Implications on Plan Period and Beyond

ENBRIDGE

Demand horizon	Major themes
Plan Period	Demonstrate criticality of gas assets for meeting Ontario's energy needs in an affordable, secure, reliable and resilient manner relative to electricity sector Reflect lower than historical customer and capacity additions as a result of energy transition policies Eliminate revenue volatility by implementing fixed charge recovery of fixed costs (2025/26 implementation) and deferral account treatment for volume variances starting in 2024. Optimize investments in gas carrying assets, demonstrate prudence by considering demand reductions and non pipeline solutions before adding pipe assets (Integrated Resource Planning), modest investments in lower carbon gas projects (RNG, hydrogen)
Net Zero	Commissioned third party study on net zero pathways to inform future policy direction. Diversified pathway including low carbon fuels is $200B and 27% less expensive than electrification pathway. Study presumes the displacement of natural gas with hydrogen over time, with larger volume flow from blended gas Demonstrate depreciation expense estimates based on 2050 Economic Planning Horizon

Harmonization proposals add complexity to case

ENBRIDGE

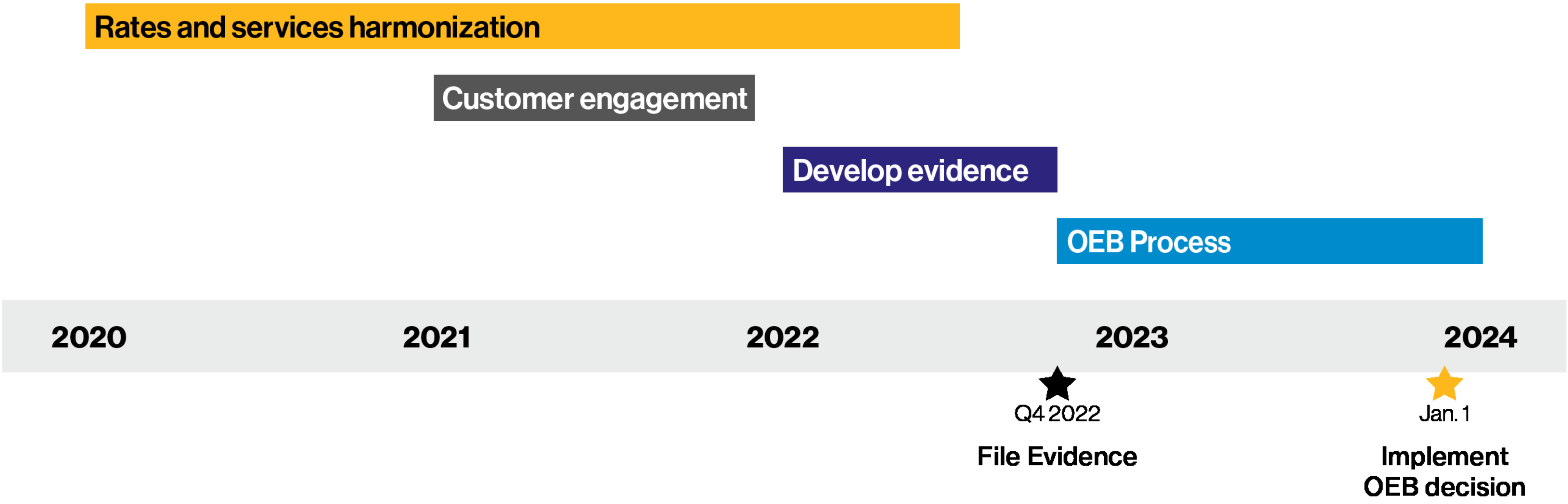
OEB requires cost allocation and rate harmonization proposals from amalgamation	Impacts on rates and timelines
Revised design criteria for gas supply procurement and distribution planning replacing legacy criteria	Rates impact: neutral When: 2024
Gas supply and delivery cost harmonized across province replacing geographical differentiation	Rates impact: range of decreases and increases When: 2024
Depreciation expense methodology replacing legacy approaches	Rates impact: significant to some customer groups When: 2024
Customer Service and Rate Harmonization across province	Rates impact: significant to some customer groups When: implemented in 2025 and 2026

Investigate options to contain scope or move to other process to manage Jan. 1, 2024 timeline

Next Steps

ENBRIDGE

- Oct. 31: File revenue requirement and incentive framework evidence
- Nov. 30: File cost allocation and rate design evidence including rate harmonization proposal



Gas Distribution and Storage Update

Board of Directors
February 1, 2022

Rebasing and Incentive Rate Mechanism

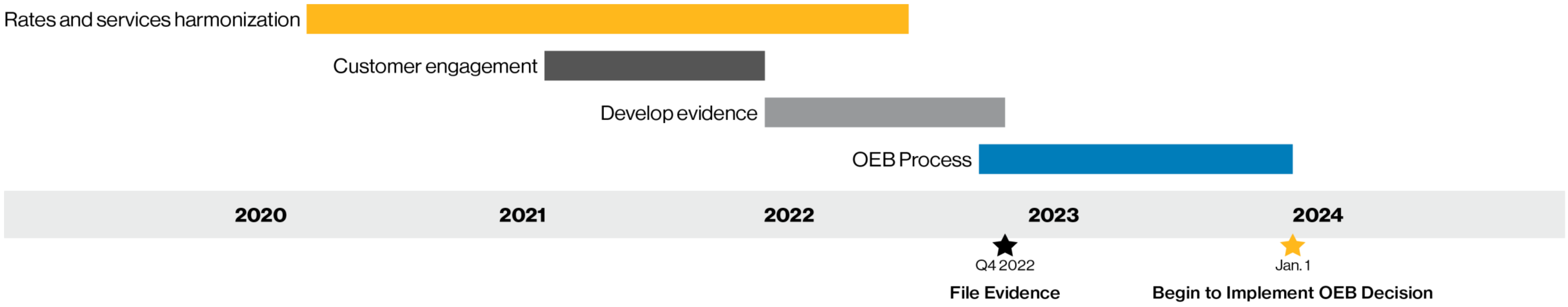
- Both legacy utilities have operated within a form of incentive rate mechanism since 2013, which was the last Cost of Service (rebasing) application for both utilities
- Since amalgamation in 2019, the utility has exceeded allowed ROE under a Price Cap Framework
- Rebasing application required for 2024 and incentive rate mechanism for 2025-2028

2024 rebasing requirements:

- Rates set to recover allowed cost to serve and allowed return on capital
- Transfer shareholder benefit from utility amalgamation (2019-2023) to ratepayers
- Rate zone and service harmonization

2025 – 2028 incentive framework: Price Cap

- Rates escalated annually for inflation and productivity factors
- Formula applied to 2024 Rates
- Incremental Capital Module for recovery of capital above a threshold amount



Gas Distribution and Storage Update

Board of Directors
April 26, 2022

Rebasing and Incentive Rate Mechanism

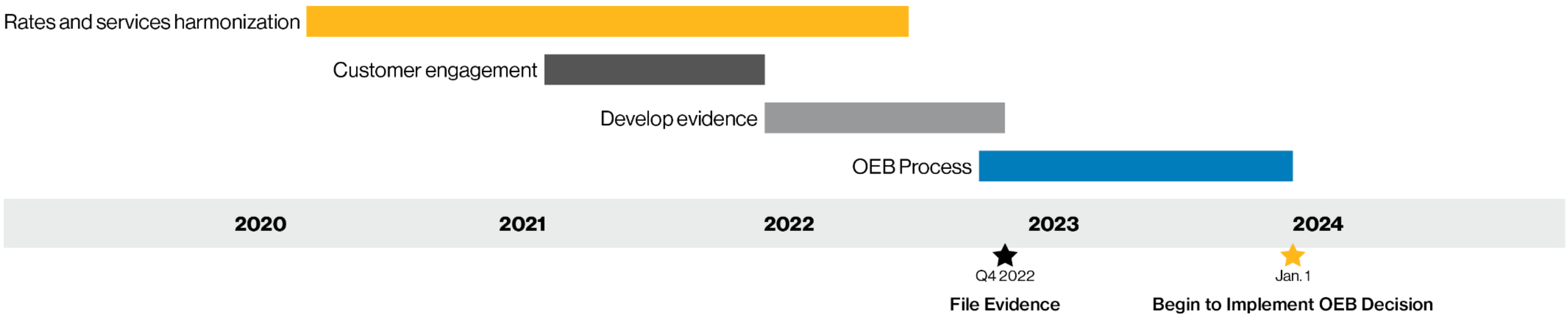
- Current MAADs* regulatory framework (2019-2023) incents integration of legacy utilities
- Cost of service (rebasing) application sets rates for 2024 then followed by incentive rate mechanism for 2025-2028

2024 rebased rates to propose:

- Integration related cost savings to be passed through to ratepayers
- Higher depreciation rates
- Single set of rates and services across franchise
- Energy transition impacts including a recommended increase in equity thickness

2025-2028 rate escalation mechanism similar to current:

- Annual factor applied to 2024 rates
- Sum of inflation index and a negative productivity factor
- Requirement to seek cost of service treatment for capital above a threshold amount (ICM)



Rebasing critical to set the economic framework for our business and to provide regulator insights into energy transition

* In 2018 the OEB issued its Decision under the Mergers Acquisitions Amalgamations Divestitures (MAADs) Policy relating to the utilities amalgamation filing

Gas Distribution and Storage Update

Board of Directors
July 18, 2022

Rebasing & Incentive Rate Mechanism 2024-28

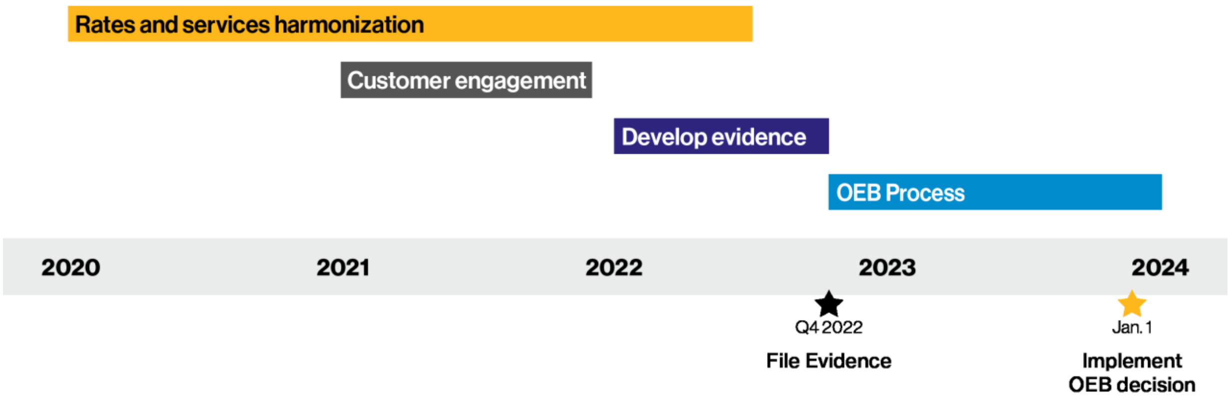
Current regulatory framework* (2019-2023) incented integration of legacy utilities. 2024 rates will be the first rebased (to cost of service) rates since 2014 and will be followed by a 4-year incentive-based rate mechanism.

2024 rebased rates to include:

- Cost savings from integration returned to ratepayers
- Cost increases from inflationary environment
- Return on installed 2024 rate base
- Proposal for higher harmonized depreciation expense and single set of rates and services across franchise
- Energy transition considerations
  - Higher equity thickness to reflect increased risk
  - Assurance of recovery of invested capital aligning with pace of transition

2025-2028 rate escalation mechanism to include:

- Inflation index, productivity factor, wage escalator
- Opportunity to earn above allowed return through efficiency gains
- Mitigation of capital risk through cost of service treatment for capital above a threshold amount (ICM)



Rebasing proceeding critical to set the economic framework for our business

* In 2018 the OEB issued its Decision under the Mergers Acquisitions Amalgamations Divestitures (MAADs) Policy relating to the utilities amalgamation filing

Gas Distribution & Storage Update

Board of Directors
January 31, 2023

ENBRIDGE®

Regulatory Update

ENBRIDGE

2024 Rebasing Application

- Seeking cost of service rates for 2024 and a price cap rate-setting incentive mechanism for 2025 – 2028
- Revenue deficiency due to cost pressures, higher depreciation expense and increase in equity thickness partially offset by synergies from amalgamation
- OEB process to hear the application and evidence underway. Expected decision on items that affect Jan. 1, 2024 rates in fall 2023

Next steps:

- Feb. 10: Interrogatories received by EGI
- March 8: EGI files responses to interrogatories
- March 22 – 28: Technical Conference
- May 9 – 17: Settlement Conference

Energy Conservation & Marketing

- Demand Side Management Plan application approval received from OEB
- $167MM annual budget in 2023, increasing by 3% plus CPI inflation
- Continued ability to earn shareholder incentive ~$6 – $9MM/year
- January 2023: Launched jointly funded Home Energy Retrofit Plus program that combines both NRCan's Greener Homes[1] and DSM funding
- Total conservation program funding increases to $330MM/year in 2023

Leave-to-Construct

- Four community expansion applications in various stage of regulatory review; an additional six to be filed by year-end
  - Represents ~6,100 new customer connections
- Three RNG leave-to-construct applications to be filed within 2023
  - Ridge Landfill RNG (2.3 MMscfd of RNG): pending approval
- Dawn to Corunna: OEB approved application as filed
- Panhandle Regional Expansion Project: application in abeyance; update due to OEB on or before Feb. 1, 2023

[1] Greener Homes is an NRCan program that is available between 2023 and 2027.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Question(s):

Please indicate to what extent EGI had discussions with the Ontario Government regarding this Application particularly with respect to energy transition. Please provide all materials, including letters, emails, and presentations related to any discussions with the Ontario Government regarding this Application.

Response:

Enbridge Gas held four meetings throughout September and October 2022 with the Ontario Ministry of Energy officials and staff to provide an overview of Enbridge Gas's Rebasing Application. The materials presented at the meetings are provided at Attachment 1 and Attachment 2. Enbridge Gas also distributed a Rebasing Application issue brief, provided at Attachment 3, to the Ontario Ministry of Energy in November 2022 as a follow up to the October briefings.

Enbridge Gas also provided briefing meetings in August and September 2022 to the Ontario Ministry of Energy and the Ontario Ministry of Environment, Conservation and Parks regarding the Pathways to Net-Zero Emissions for Ontario Report included in the Rebasing Application. This presentation is provided at Attachment 4.

In addition, a briefing meeting was held in October 2022 with the Ontario Ministry of Environment, Conservation and Parks regarding the Company's Renewable Natural Gas blending program included in the rebasing application. This presentation is provided at Attachment 5.

2024 OEB Rate Rebasing Application

ENBRIDGE
Life Takes Energy

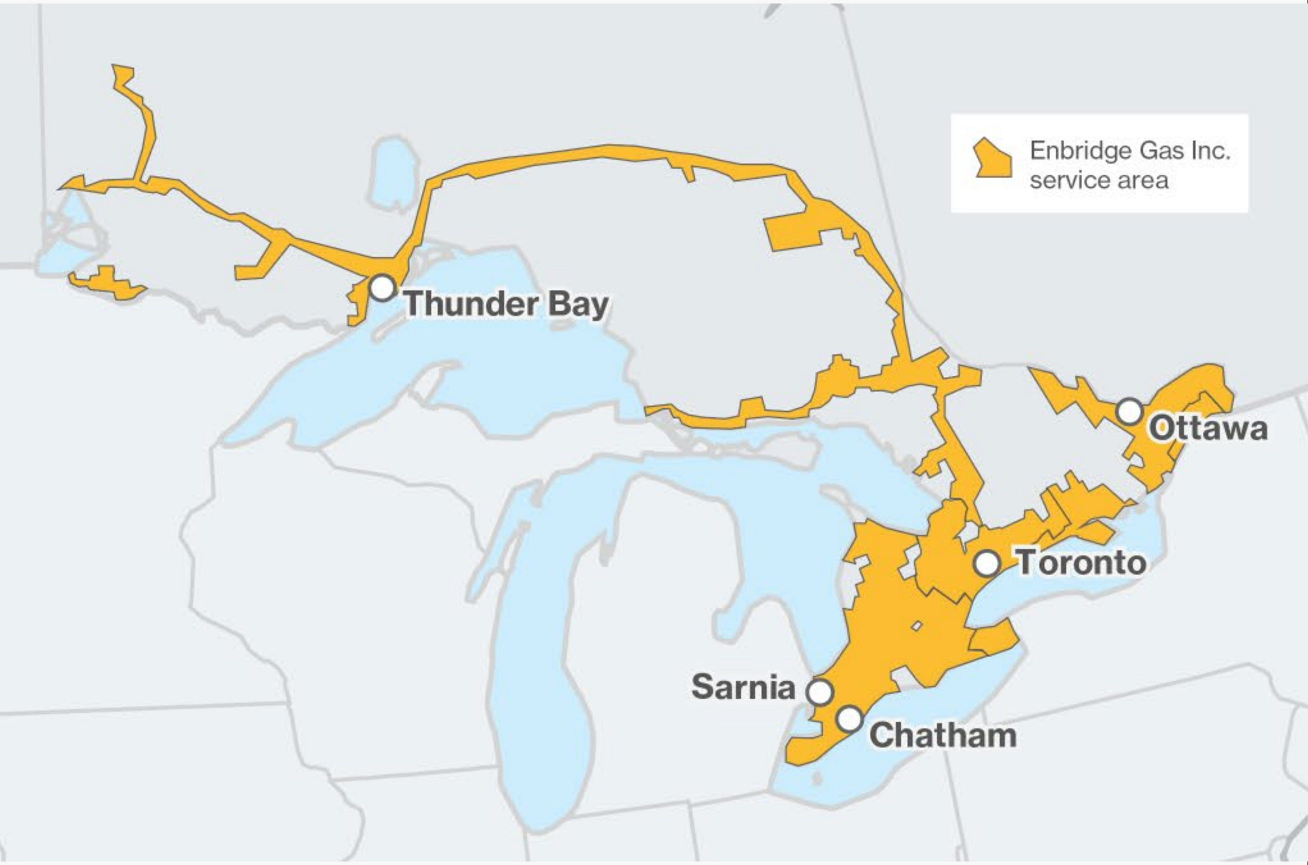
August 2022

Enbridge Gas Inc.

North America's largest gas storage, transmission and distribution company

We deliver the energy that enhances people's quality of life.

- **Values**
  Safety, Integrity, Respect, Inclusion.
- **Ambition**
  To be the sustainable and reliable energy provider of choice.
- **Experience**
  170+ years of experience in safe and reliable service.
- **Distribution Business**
  3.8M customers, heating >75% of Ontario homes and delivering 30% of Ontario's energy needs.
- **Dawn Storage Hub**
  Canada's largest integrated underground storage facility and one of the top gas trading hubs in North America.
- **Leading Ontario's transition to net-zero emissions**
  Advancing conservation, renewable gasses and clean technologies for heat, transportation and industrial processes.



Formed Jan. 1, 2019 from the amalgamation of Union Gas Limited and Enbridge Gas Distribution.

Overview

- OEB requires Enbridge Gas and other utilities to bring a cost of service application every 5 years to "rebase" or reset rates.
- Enbridge Gas last filed for cost of service rates in 2013 and had a deferred rebasing period (2019-23) due to the amalgamation of EGD and Union Gas
- Enbridge Gas will be filing in October, 2022 for new rates effective Jan 1, 2024 and a price cap formula for 2025-28
- Key themes include:
  - Increase in cost to serve customers in 2024
  - Harmonization of services, costs and rates
  - Energy Transition considerations and initiatives

Rebasing Application Timeline

Process Step	Estimated Timing
Notice	November, 2022
Interventions received	December, 2022
Procedural Order 1	January, 2023
Community meeting	January, 2023
Final issues list	early February, 2023
Interrogatories	mid-February to mid-March, 2023
Technical conference	late March to early April, 2023
OEB staff/Intervenor evidence	early April, 2023
IRs on intervenor evidence	late April, 2023
Settlement conference	early to mid-May, 2023
Oral Hearing	June, 2023
Argument (3 steps)	July to early August, 2023
Decision	October, 2023
Rate Order process	November, 2023
Implement new rates	January 1, 2024

Cost to Serve in 2024

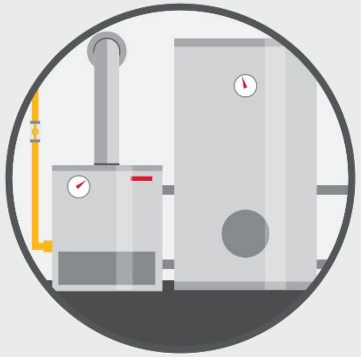
- Factors reducing costs include
  - Synergies realized by establishing integrated organization structures and aligning programs, processes and systems, including financial systems
  - Productivity savings examples include digital adoption and emergency call handling
- Factors increasing costs include
  - Inflation affecting several cost categories including fuel, postage, outside services
  - Safety and reliability through integrity and distribution protection (locates)
  - Bad debt increase from trend in arrears
  - Labour costs
  - Capital expenditures in excess of the amount supported by rates
  - Depreciation expense and equity thickness

Harmonization of legacy utilities

- Demand forecasting methodology and planning criteria
- Gas commodity price setting across province
- Depreciation rates for asset classes across province
- Customer attachment policies
- Cost allocation and Rate harmonization to a single rate handbook
  - Striving for single rate zone across province
  - Shift to straight fixed variable rate design for all rate classes
- Deferral and Variance accounts

Energy Transition in Rebasing Application

Optimizing Assets



- Implementation of Integrated Resource Planning through conservation, supply side alternatives to facilities
- Forecasting lower customer additions and smaller peak load additions

Green Gas

Reducing emissions via introducing low or no carbon gasses:

- Hydrogen: Power to Gas
- Renewable natural gas (RNG)

Conversion to Gas

Reducing emissions via displacing higher carbon fuels with natural gas in:

- Industrial processes
- Transportation

Gas Innovation

Reducing gas sector emissions via:

- Energy Transition Technology Fund (ETTF)
- Mention of CCUS

Evolving Gas Sector Systems

Reducing gas sector emissions via:

- Responsibly Sourced Gas (RSG)
- Reducing Enbridge Gas' Scope 1 emissions

Renewable Natural Gas

Blending Renewable Nature Gas

- RNG is created from processing existing waste, such as waste from food, agricultural or landfill sources. This waste is recovered, broken down using anerobic digestion and upgraded into RNG.
- This gas can be added to existing natural gas infrastructure and is a one-for-one replacement of conventional natural gas.
- Enbridge Gas is looking to evolve the current RNG program to make it easier for more customers to consume greater quantities low carbon energy.
- Taken steps to work towards incorporating energy transition in the gas supply commodity portfolio via the proposed Low Carbon Voluntary Program (LCVP) and the current Voluntary Renewable Natural Gas (VRNG).
- RNG, being carbon neutral, and exempt from the Carbon Charge, is one of the best ways to lower GHG emissions affordably.

Low Carbon Voluntary Program

- We will be seeking to increase our low carbon energy in system supply beginning at 1% in 2024 increasing by one percent per year until reaching 5% by 2028 with two mechanisms for cost recovery.
  - LCVP – will offer a customizable program to large volume sales service customers to upgrade their supply to RNG.
  - Incorporate the costs of low carbon energy that are not covered in the LCVP in the commodity reference price to have costs recovered as part of all system supply.
- Target customers are firm, large volume sales service.
- Customers have an annual option to elect that a portion of their following gas year's consumption is upgraded to RNG.

How will we Execute This?

- Enbridge will buy RNG in a large quantity and release a notice for customers to consider inclusion at the RNG Portfolio Rate.
- Large volume customers will have the ability to express interest and indicate the portion of their supply they'd like to upgrade to RNG.
- Customers will be charged for the RNG over the year for the quantity selected.
- Any quantity not voluntary elected by large volume customers, will be put into the natural gas distribution system as a part of all system supply.

Forecast Bill Impacts

RNG Blend Increase Costs for Average Residential Customer

RNG Bill Impacts	Blend %	Cumulative Annual Bill Increase	Cumulative Monthly Bill Increase Excluding FCC Impact	Cumulative Increase Over July 2022 Average Bill	Year over Year Increase
2024	1.0%	$ 22.84	$ 1.90	1.835%	
2025	2.0%	$ 45.83	$ 3.82	3.681%	1.85%
2026	3.0%	$ 68.88	$ 5.74	5.532%	1.85%
2027	4.0%	$ 91.90	$ 7.66	7.382%	1.85%
2028	5.0%	$ 114.92	$ 9.58	9.231%	1.85%

RNG Blend Increase Costs for Average Residential Customer with Carbon Charge Reduction

RNG Bill Impacts	Blend %	Cumulative Annual Bill Increase	Cumulative Monthly Bill Increase Including FCC Reduction	Cumulative Increase Over July 2022 Average Bill	Year over Year Increase
2024	1.0%	$ 18.99	$ 1.58	1.525%	
2025	2.0%	$ 36.66	$ 3.05	2.944%	1.42%
2026	3.0%	$ 52.90	$ 4.41	4.249%	1.30%
2027	4.0%	$ 67.69	$ 5.64	5.437%	1.19%
2028	5.0%	$ 81.03	$ 6.75	6.508%	1.07%

Enbridge will seek to place a cap of $2/month per percentage of RNG in the supply portfolio for average residential customers.

Benefits of a Blend

- Accessing made-in-Ontario RNG supply as soon as possible will allow the environmental benefits of RNG to remain in province and ensure Ontarians have access to the most economic supply of RNG while supply is still available. The longer Ontario waits, the higher the price we will be subject to.
- To give both large volume and small volume customers the best access to cost-effective RNG supply, Enbridge is aligning the RNG demand of these two types of customers with the proposed program and can seek cost-effective long term RNG contracts.
- RNG displacing conventional natural gas creates Clean Fuel Regulation Credits. The value of these credits is still developing as that market begins to become more active. The value of these credits generated could be streamed to customers to reduce the cost of RNG.

Environmental and Economical Benefits

- If we have ~40 projects to meet the supply needed in 2030 we'd have up to 1000 full-time jobs after development of the project, creating significant economical benefits.
- An RNG blend of 5% by 2028 will meet 7% of the government of Ontario's GHG emissions reduction goal with this alone.
  - The emissions reductions would be equivalent to removing 280,000 gas-powered vehicles from the road for one year.
  - Over 50% of Enbridge's customers supported a blend of up to 5% RNG in our 2022 customer engagement.

Q&A

Enbridge Gas
2024 Rebasing Follow-up

ENBRIDGE®
Life Takes Energy®

October, 2022

Key Components of Application

- Cost of service components:
  - Capital expenditures
  - Revenue forecast
  - Operating costs
  - Cost of capital
- Harmonization of forecasting methodologies (e.g. demand forecast) and planning assumptions (e.g. system design criteria, average use)
- Alignment and update of depreciation methodologies and depreciation study
- Equity thickness change
- Incentive rate mechanism
- Rates and services harmonization

Proposed Deficiency and Drivers

ENBRIDGE
Life Takes Energy

In $ millions

Net sustainable synergies and productivity	(67)
Changes in accounting policy and methodologies	(26)
Impact related to ICM and Capital Pass Through projects	42
Deferred Rebasing Impact	**(51)**
Cost pressures	70
Depreciation	198
Equity thickness	25
Cost of Service Impacts	**293**
Total Delivery Revenue Deficiency	**242**
Gas Supply Deficiency	**23**
Total Deficiency	**265**
Total Revenue Requirement	6,279
Deficiency as a % of Revenue Requirement	4%

Rate Class Harmonization

- Rate harmonization plan includes a proposal to harmonize rate classes

Service Description	Harmonized Rate Class	Current Rate Classes		
		EGD	Union South	Union North
General Service	E01 – Small General E02 – General	1 6	M1 M2	01 10
Firm Contract	E10 – Firm Bundled	100 110 115	M4 M7	20 100
Large Firm Contract	E20 – Semi-Unbundled E22 – Unbundled E24 – Extra Large Unbundled	300 125	T1 T2	20 100
Other Contract Services	E30 – Interruptible E34 – Seasonal Firm E38 – Unbundled Storage	145 170 135 315 316	M4/M5 M7	25
Wholesale	E60 – Wholesale Transportation E62 – Bundled E64 – Semi-Unbundled	200	M17 M9 T3	
Ex-franchise Transportation	E70 – Transportation E72 – Transportation for Embedded Storage Pools	331/332	M12/C1 M16	
Ex-franchise Other	E80 – Producer Injection and Transportation Service E82 – Renewable Natural Gas Injection Service	401	M13/GPA	
Proposed for Elimination		9 320 325 330	M10 U2	30

Energy Transition (ET) in Rebasing

- Enbridge Gas will present the following ET aspects in rebasing
  1. Role of natural gas in meeting Ontario's energy demand on an annual and peak basis during the rebasing period relative to the capabilities of the Ontario electricity sector
  2. How Enbridge Gas is mitigating future natural gas demand uncertainty during the rebasing and AMP planning horizons via the:
     - Integration of ET considerations into the application, with a focus on impacts to the AMP, finance and regulatory approaches
     - Maintenance of the gas system with consideration of natural gas demand uncertainty at the forefront
  3. Work undertaken to understand potential future pathways and their impacts on Enbridge Gas
     - Scan of government policies, plans and strategies
     - Customer engagement
     - Scenario analysis and pathways studies; a diversified pathway was found to achieve net-zero in Ontario more affordably, and with greater reliability, resiliency, consumer choice and industrial competitiveness.

Energy Transition (ET) in Rebasing

- Enbridge Gas will present the following ET aspects in rebasing - Continued

4. Enbridge Gas's ET Plan (ETP), which focuses on "safe bet" actions that Enbridge Gas is exploring, pursuing or proposing; these are actions that:
   - Support Ontario's near term GHG emissions reductions, including achievement of the 2030 target, and/or
   - are required, regardless of whether a diversified or an electrification pathway unfolds in Ontario, and/or
   - Maintains consumer choice, pathway optionality, and/or a safe and reliable gas system in a manner that considers pathway uncertainty

5. Enbridge Gas's ET safe bet rebasing specific proposals that, if approved, can drive continued GHG emissions reductions over the rebasing period while Ontario's Electrification and Energy Transition Panel completes their Pathways Report and next steps.

Low Carbon Voluntary Program Update

- We will be seeking to increase our low carbon energy in system supply beginning with 1% in 2025 and increasing by one percent per year until reaching 4% by 2028 with two mechanisms for cost recovery.
  - LCVP – will offer a customizable program to large volume sales service customers to upgrade a portion of their supply to RNG.
  - Incorporate the costs and benefits of low carbon energy that are not covered in the LCVP in the commodity reference price to have costs recovered as part of all system supply.
- An RNG blend of 4% by 2028 will meet 6% of the government of Ontario's GHG emissions reduction goal with this alone.
  - The emissions reductions would be equivalent to removing 230,000 gas-powered vehicles from the road for one year.
  - Over 50% of Enbridge's customers supported a blend of up to 5% RNG in our 2022 customer engagement.

RNG Forecast Bill Impacts

RNG Blend Increase Costs for Average Residential Customer

RNG Bill Impacts	Blend '	Cumulative Annual Bill Increase	Monthly Bill Increase Excluding FCC Impact	Cumulative Increase Over July 2022 Average Bill	Year over Year Increase
2025	1.0%	$ 22.91	$ 1.91	1.840%	1.84%
2026	2.0%	$ 45.92	$ 3.83	3.688%	1.85%
2027	3.0%	$ 68.93	$ 5.74	5.536%	1.85%
2028	4.0%	$ 91.94	$ 7.66	7.385%	1.85%

RNG Blend Increase Costs for Average Residential Customer with Carbon Charge Reduction

RNG Bill Impacts	Blend '	Cumulative Annual Bill Increase	Monthly Bill Increase Including FCC Reduction	Cumulative Increase Over July 2022 Average Bill	Year over Year Increase
2025	1.0%	$ 18.33	$ 1.53	1.472%	1.47%
2026	2.0%	$ 35.27	$ 2.94	2.833%	1.36%
2027	3.0%	$ 50.77	$ 4.23	4.078%	1.25%
2028	4.0%	$ 64.82	$ 5.40	5.207%	1.13%

These bill impacts are only if there is no voluntary pickup from large volume customers, Enbridge doesn't believe this will be the case.

Overall Rate Rebasing Bill impacts

- 2024 bill impacts are a function of
  - Revenue requirement deficiency
  - Cost allocation harmonization
  - Gas cost recovery implementation
- Rate class harmonization bill impacts
  - Planned for 2025 for general service rate classes and 2026 for contract rate classes
- Rate mitigation plan
  - Limited use

Total Bill Impacts – General Service

Rate Zone Rate Class	Total Bill Impact 2024	 Rate Class/Design Harmonization
EGD		
Rate 1	2% to 4%	0% to 2%
Rate 6	1% to 3%	2% to 4%
Union North West		
Rate 01	-4% to -2%	0% to 2%
Rate 10	-2% to 0%	-2% to 0%
Union North East		
Rate 01	-12% to -10%	0% to 2%
Rate 10	-12% to -10%	-2% to 0%
Union South		
Rate M1	8% to 10%	0% to 2%
Rate M2	5% to 7%	0% to 2%

- Bill impacts are preliminary estimates
- Total bill impact representative of a typical customer profile in each rate class
- Total bill impact assumes the total bill of a sales service customer
- 2024 total bill impact includes impact of disposition of deferral and variance accounts in 2024

Next steps

- Revenue requirement and IRM target filing October 31, cost allocation & rate design November 30
- Implementation – new rates effective January 1, 2024, with proposed harmonization of general service rate classes in 2025 and contract rate classes in 2026

Q&A

ENBRIDGE Issue Brief

Nov. 14, 2022

2024 Rebasing Application

Background

Enbridge Gas has filed an application to initiate a regulatory process which will determine the rates the utility can set for its customers for 2024 and the mechanism through which Enbridge Gas will set rates from 2025 to 2028. Because Enbridge Gas is a regulated entity, it applies to the Ontario Energy Board (OEB)—typically every five years—to approve a new "base" rate and a rate-setting formula for subsequent years.

Since its Oct. 31 filing, Enbridge Gas has now received a Letter of Direction (LoD) from the OEB that a Notice of Hearing for Enbridge Gas's rate rebasing application will be included in the Globe and Mail, the Toronto Star, National Post, 2 French papers and 2 Indigenous papers. All Enbridge Gas customers for whom Enbridge Gas has an email address will also be receiving an email with the same information. The OEB has directed Enbridge Gas to serve notice to all customers.

Key Messages

- Enbridge Gas has filed an application with the Ontario Energy Board (OEB) to initiate a regulatory process called rebasing to determine the fair and reasonable regulated distribution, transmission and storage rates that Enbridge Gas will charge customers in 2024 to recover the basic costs of serving our customers safely and reliably.
- In addition Enbridge Gas is proposing an incentive regulation structure which applies a formula that includes items such items as inflation to determine the rates we will charge customers for the following four years from 2025 to 2028. This incentive regulation structure is very similar to the one used to set the utility's rates from 2019 to 2023.
- Enbridge Gas is focussed on its customers and undertook extensive engagement with customers, talking to more than 12,000 in 2021 and early 2022. Those customers showed Enbridge they care most about energy affordability, reliability, and minimizing environmental impacts.
- The proposed rates in this application will support a system that can continue to meet customer needs safely and reliably in a cost-effective way, while at the same time helping to prudently prepare for the energy transition that is underway in the communities where they live, driven by existing and planned federal and provincial policies.
- The application is focused on delivering value to customers in four ways:
  1. Affordability
     - As a result of the amalgamation in 2019, Enbridge Gas is delivering significant benefits to customers, with productivity savings, customers will benefit from more than $120 million in sustained annual savings.
     - This is offsetting the rising costs of operating its business and moderates the rate increases necessary to continue delivering safe and reliable service to customers in 2024.
  2. Reliability
     - The application includes prudent long-term capital investment plans to ensure continued safe, reliable, cost-effective operations while also minimizing environmental impacts.
  3. Minimizing environmental impact

- The application includes Enbridge Gas' first Energy Transition Plan which lays out how it is proposing to balance customers' needs for continued access to a cost-effective supply of energy with actions that support Ontario's near-term GHG reduction goals.
- The long-term asset management plan reflects the OEB's Integrated Resource Planning Framework, a process that evaluates alternative ways to meet the demand for natural gas such as reducing gas use through conservation, to avoid or reduce the need to build new pipelines.

4. Simplification and harmonization of rates and services
    - Since the amalgamation in 2019, many systems and services were harmonized for a consistent and simplified customer experience. To further reflect the operations and services of a single utility, Enbridge Gas proposes to further align and simplify our rates and customer services, and to phase in these changes to allow time to implement system changes and inform customers.

- Taking all these items into account, Enbridge Gas is seeking a 4% increase in its 2024 revenues relative to 2023 to cover the rising costs of operating its business.
- Enbridge believes the proposed rates are reasonable and necessary to support the kind of energy solutions the engagement sessions showed they expect, to provide a consistent and improved customer experience, and to meet government goals addressing climate change, and incorporate more than $120 million in annual savings realized from productivity and the integration of the two legacy utilities.
- Included in the rebasing application, Enbridge Gas proposes to blend 1% of RNG starting in 2025 increasing to 4% by 2028. This program will be offered to large volume customers on a voluntary basis and if the target is not met Enbridge Gas proposed to share the rest of the commitment with all customers, capping the impact at $2 a month per customer.

Pathways to net zero:

Scenarios and actions for Ontario

Summary and recommendations for regulators and policymakers

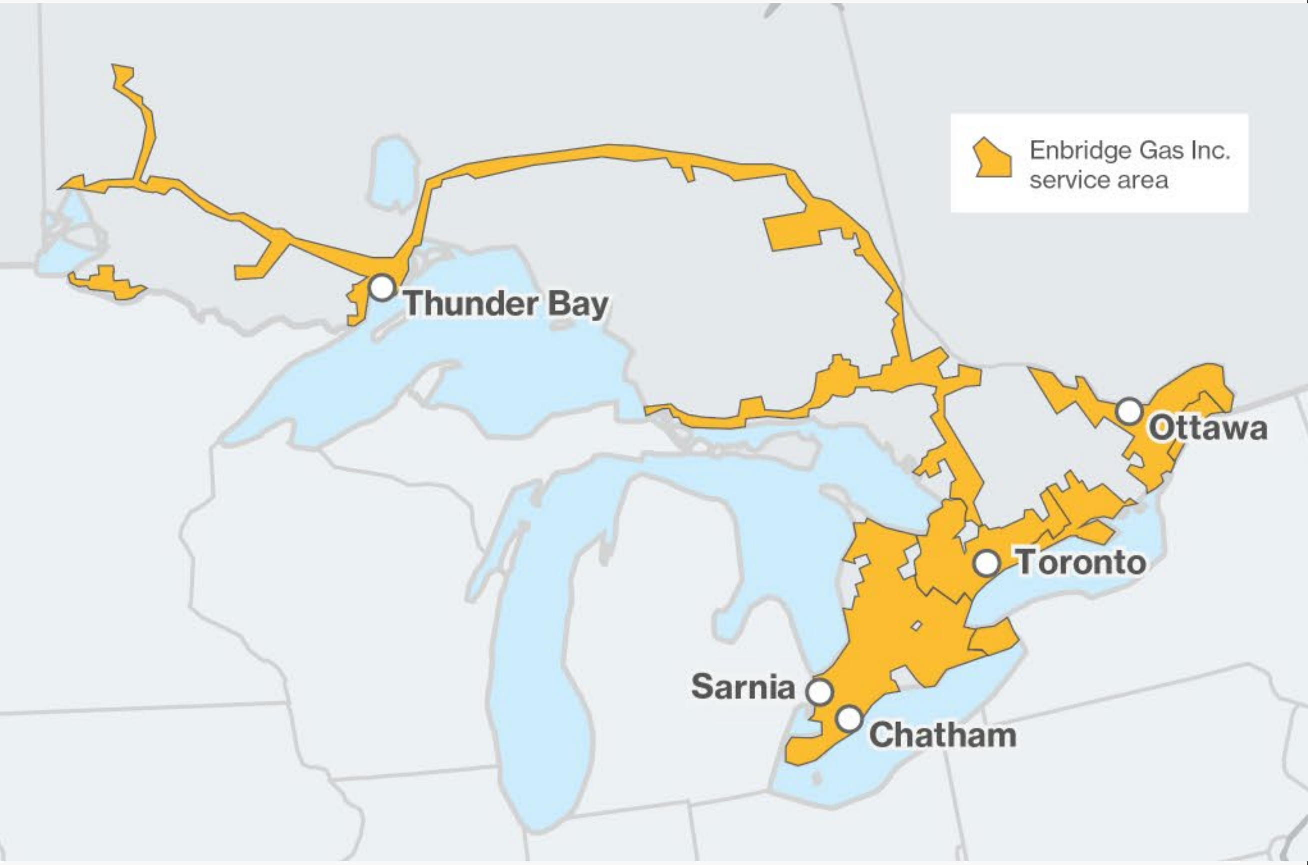
ENBRIDGE

Enbridge Gas Inc.

North America’s largest gas storage, transmission and distribution company

We deliver the energy that enhances people’s quality of life.

- **Values**
  Safety, Integrity, Respect, Inclusion.
- **Ambition**
  To be the sustainable and reliable energy provider of choice.
- **Experience**
  170+ years of experience in safe and reliable service.
- **Distribution Business**
  3.8M customers, heating >75% of Ontario homes and delivering 30% of Ontario's energy needs.
- **Dawn Storage Hub**
  Canada’s largest integrated underground storage facility and one of the top gas trading hubs in North America.
- **Leading Ontario’s transition to net-zero emissions**
  Advancing conservation, renewable gasses and clean technologies for heat, transportation and industrial processes.

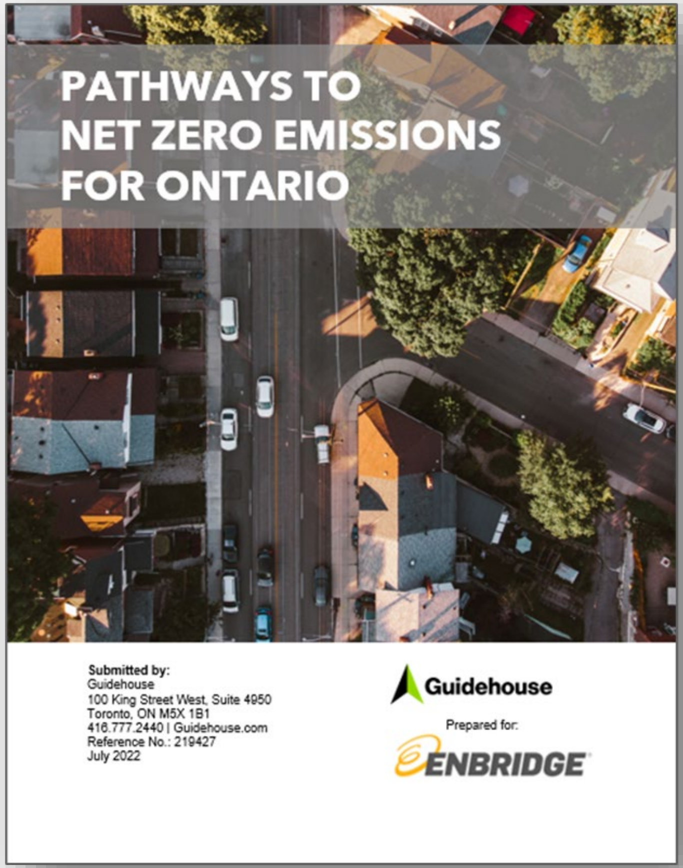


Formed Jan. 1, 2019 from the amalgamation of Union Gas Limited and Enbridge Gas Distribution.

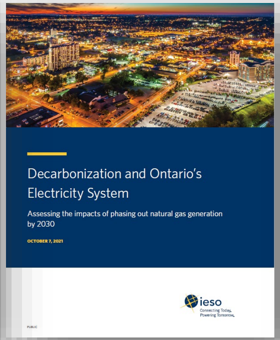
Executive summary

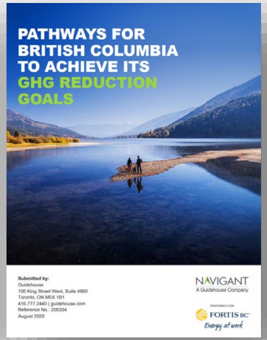
- Enbridge is committed to supporting the achievement of a clean energy future in Ontario.
  - Actively working on solutions to help meet Ontario's energy needs, while reducing emissions cost effectively.
  - Proactively engaged a consultant to evaluate energy system pathways to net zero.
- Approximately 30 percent of emissions in Ontario are from the use of natural gas.
- While Ontario is on track to meet its 2030 emission target of 30 percent below 2005 levels, achieving net zero requires more investment in renewables, lower emissions fuels and carbon capture.
- The gas distribution system in Ontario is a resource that can be leveraged to enable further GHG reductions beyond 2030, including net zero.

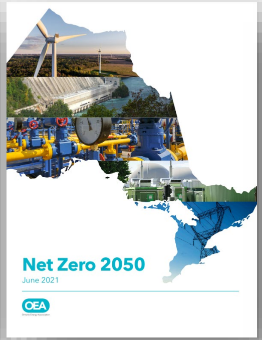
Executive summary

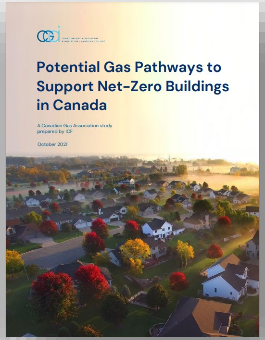


- **A diversified pathway is the most practical method to achieve net-zero emissions in Ontario.**
  - Achieving net zero will be expensive, regardless of the pathway.
  - As compared to an electrification pathway, a diversified pathway provides a lower cost, more reliable and resilient energy system, and greater consumer choice.
- This is further supported by studies conducted across North America and Europe.









Executive summary

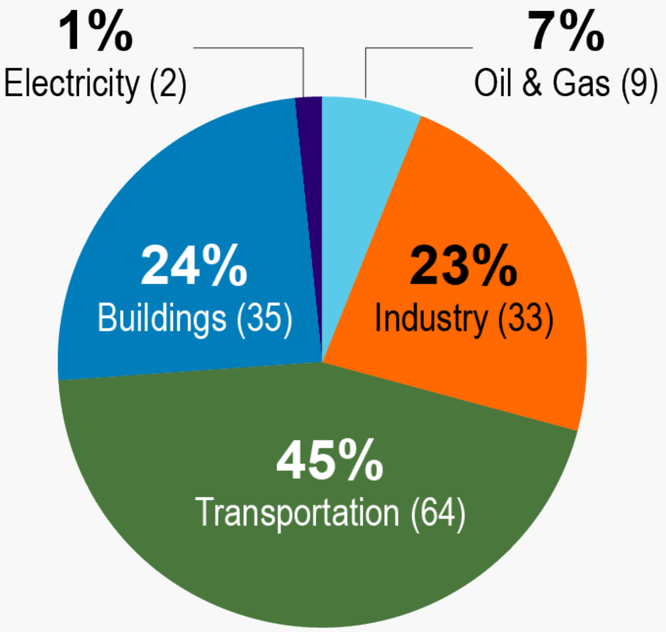
- Hybrid heating, hydrogen, renewable natural gas (RNG), and carbon capture and storage (CCS) are key elements of a diversified pathway.
- Regardless of the pathway chosen, there are “safe bet” actions that should be taken immediately for Ontario to reach net zero.
- Post-2030 targets are only achievable if investments in innovative technologies are made today
- Policies must be put in place now to enable investments.

Study approach

Two scenarios for Ontario’s energy sector

- Enbridge Gas engaged Guidehouse to evaluate two pathways to net zero:
  - **Diversified pathway***—end use electrification used in balance with low- and zero-carbon gases and natural gas paired with carbon capture.
  - **Electrification pathway**—deep electrification of all sectors with low- and zero-carbon gases and carbon capture used only where no reasonable alternative energy source exists.
- For each, the study assessed the overall feasibility based on costs, GHG emission reductions, system reliability and resiliency.
- The study also identifies what investments are needed in electricity, hydrogen and methane supply capacity, storage and infrastructure.

Emissions mix studied (143 MT)



Figures in brackets represent MT of CO2e.

*The study included sensitivity analysis which looked at how various changes in assumptions impacted the scenarios. The Diversified scenario with hybrid heating was found to be the most optimal approach to a Diversified pathway, therefore all results in this presentation are based on this Diversified scenario.

STUDY APPROACH

Pathway assumptions:

Sector	Diversified scenario	Electrification scenario	Shared assumptions
Buildings	• Gas heating transitions to low- or zero-carbon gas, including hydrogen and RNG • A large portion of residential buildings adopt hybrid heating • Some heating switches to air source and ground source heat pumps	• Electric heat pumps replace most natural gas heating in buildings • Remainder shifts to low- or zero-carbon gas	• Energy efficiency and building codes reduce heating energy demand
Transport	• Hydrogen and RNG fuel most heavy transport	• Biofuels, such as renewable diesel, fuel some heavy transport • Hydrogen limited to aviation via synthetic kerosene	• Battery-electric vehicles power light- and medium-duty transportation
Industry	• Medium- and high-temperature processes use hydrogen or methane gas with carbon capture and storage (CCS)	• Medium-temperature processes are electrified • High-temperature processes use hydrogen or methane gas with CCS	• Low-temperature processes are electrified

Study findings

STUDY FINDINGS

A diversified pathway that leverages both Ontario's gas and electric systems can achieve net zero, with greater:

Affordability

Achieves the same outcome as the electrification pathway at $202 billion less cost

Reliability

Meets the energy needs of Ontario homes and businesses, even on the hottest and coldest days of the year

Resiliency

Protects against impacts from extreme events, such as weather and cybersecurity incidents

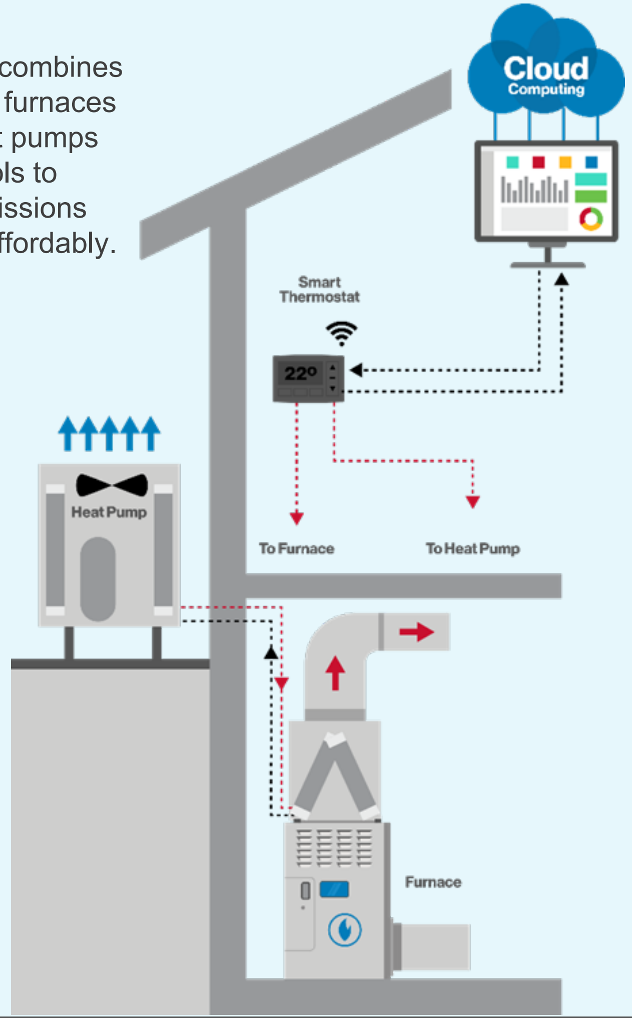
Consumer choice

Allows Ontario energy consumers the flexibility to make choices on the path to net zero

The lowest-cost pathway includes hybrid heating

- Increasing the amount of hybrid heating in the diversified pathway to 55 percent leads to lower peak electric system demand, reducing costs to achieve net zero.
- Hybrid heating uses both the electric and gas systems, increasing energy system reliability by having energy systems working together.
- Retrofitting equipment, rather than replacing it, is simpler and reduces costs for Ontarians
- Hybrid heating provides Ontarians confidence that they will have the energy they want, when they need it.

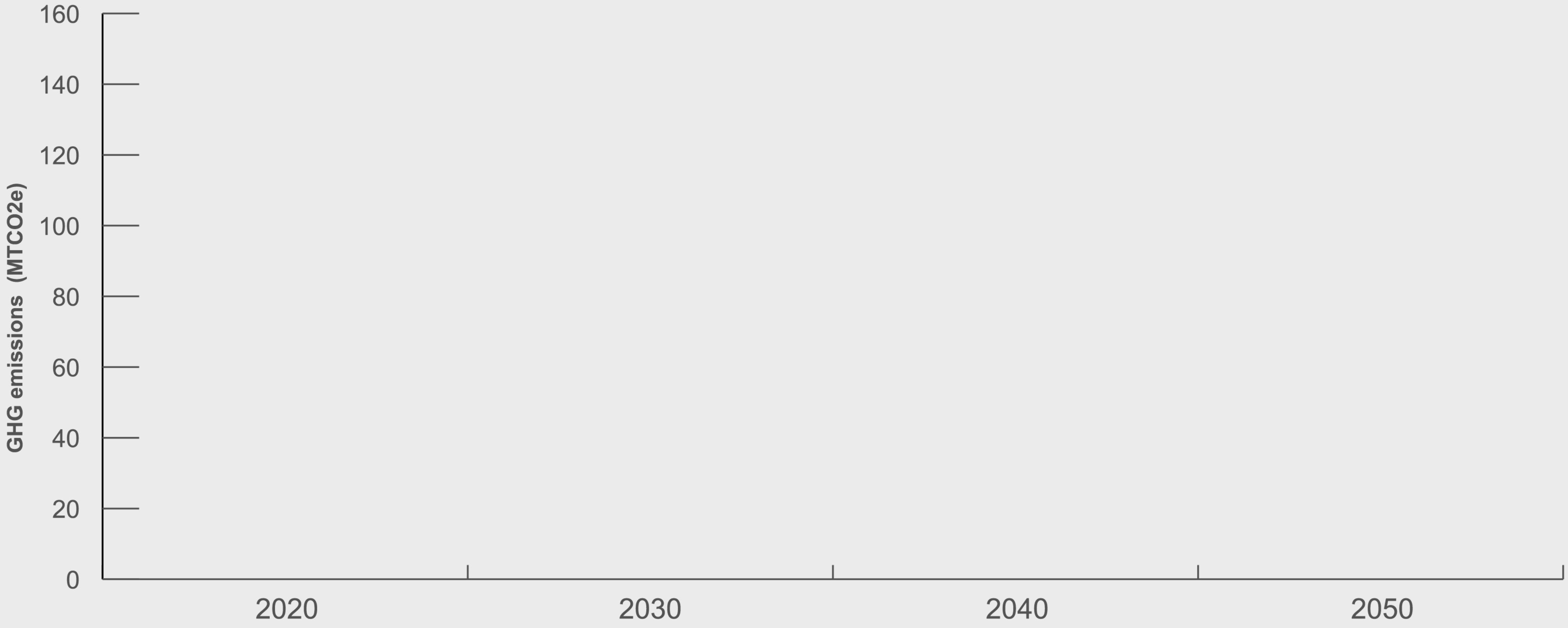
Hybrid heating combines natural gas-fired furnaces with electric heat pumps and smart controls to reduce GHG emissions practically and affordably.



Integrating the gas and electric heating systems is the lowest-cost pathway and increases system reliability.

STUDY FINDINGS

Feasibility and cost: both scenarios can achieve net zero by 2050



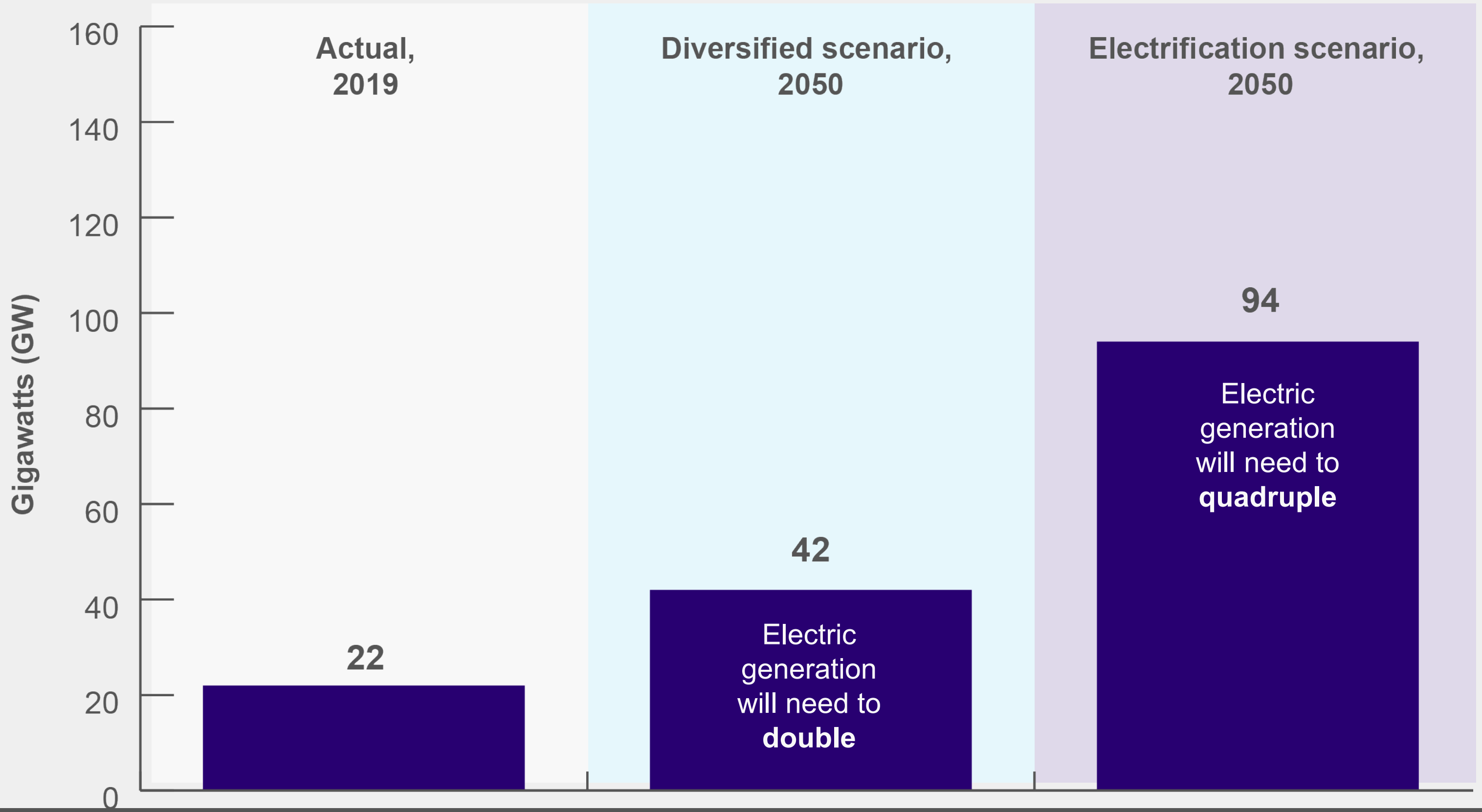
The electrification pathway will cost 27% more ($202 billion) than the diversified pathway.

STUDY FINDINGS

Meeting Ontario’s peak energy needs: electric system

- In either scenario, Ontario will need to significantly scale up electrical generation and infrastructure to meet increased demand as sectors are electrified.
- Both scenarios include energy efficiency, renewable generation and switching gas-fired generation to hydrogen to maintain reliability.

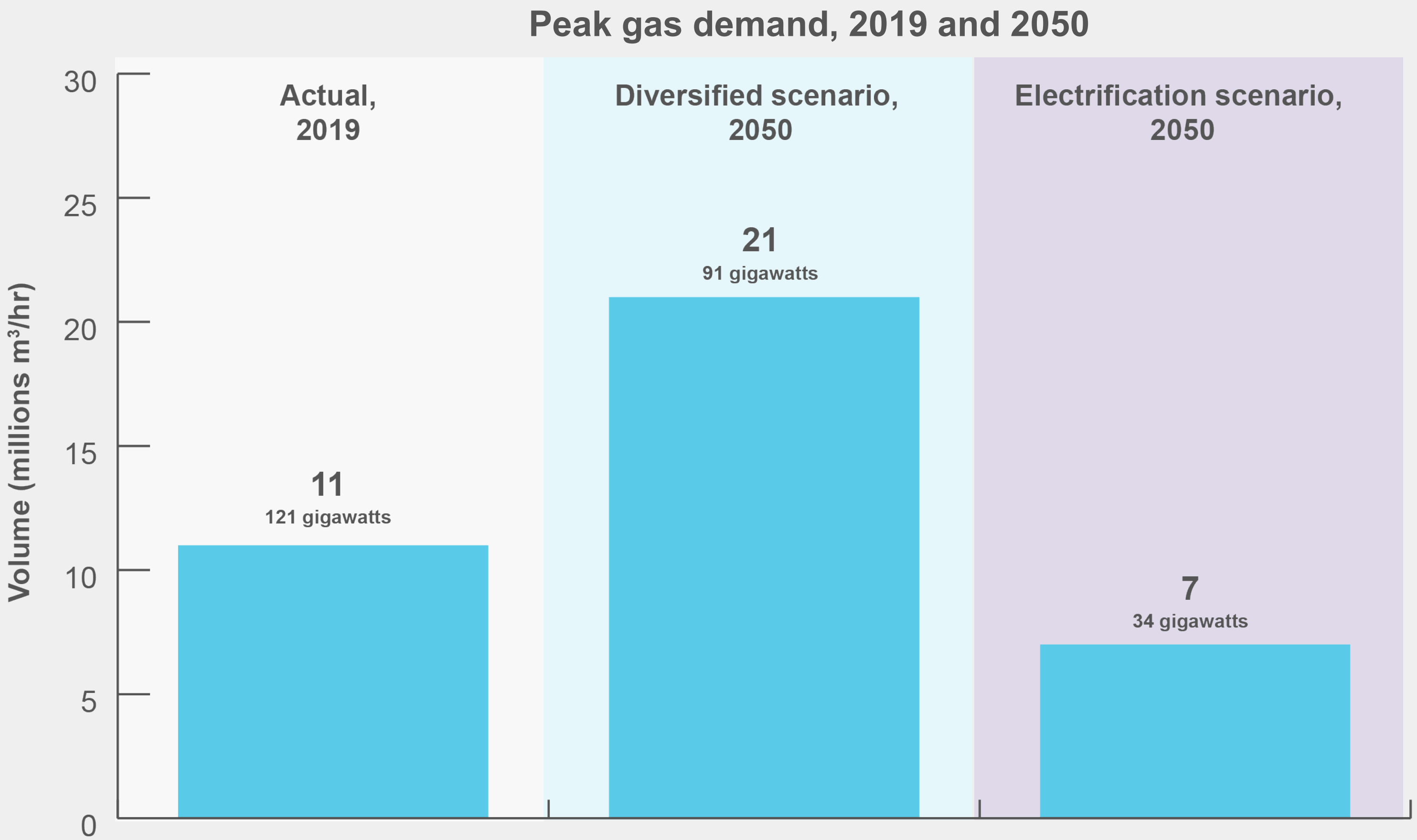
Peak electricity demand, 2019 and 2050



The diversified pathway lowers peak electricity demand, requiring less investment in the electricity system.

Meeting Ontario's peak energy needs: gas system

- In either scenario, energy efficiency, building and equipment upgrades and fuel switching lead to a decrease in gas peak on an energy basis.
- Both scenarios include hydrogen to decarbonize high-temperature industrial processes.
- The diversified scenario includes a larger amount of hydrogen, resulting in an increase in gas system peak on a volume basis.

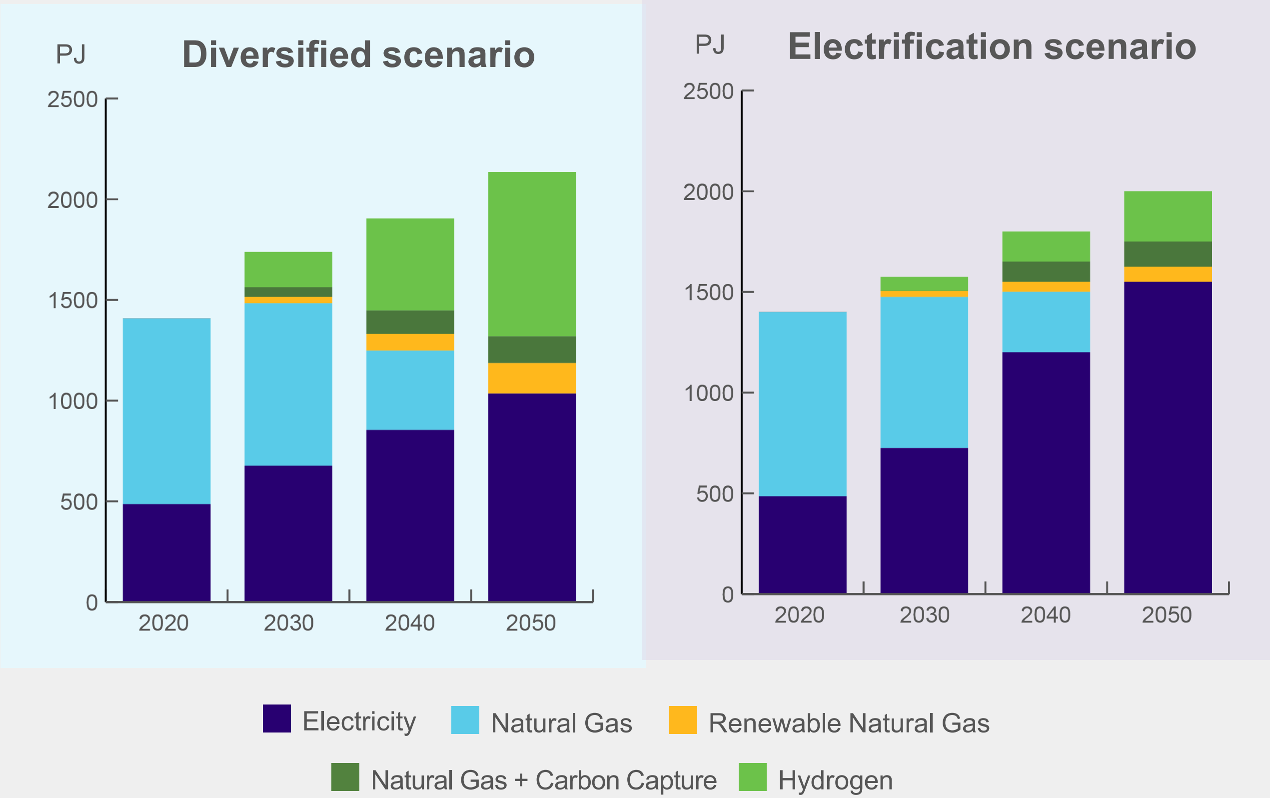


Ontario's gas system must evolve to meet increased demand for hydrogen in both scenarios.

Low-carbon gases, carbon capture are key to net zero

- Both scenarios rely on low-carbon gases such as RNG and hydrogen, and natural gas with CCS, particularly in sectors that are difficult to electrify.
- The diversified pathway uses low-carbon gasses, predominantly hydrogen, to:
  - Heat buildings
  - Provide peak energy supply, which costs less than the electrification pathway
  - Enhance grid reliability, as it acts as a storage asset for peak period power generation
  - Reduce costs to produce hydrogen for industry, compared to the electrification pathway

Energy supply mix by decade



The diversified pathway, with a greater mix of low-carbon gases, provides reliability and lower cost.

Optimizing the diversified scenario

- Modeling sensitivities show that changing the mix of energy solutions also changes the outcomes including the cost to achieve net zero.
- Further savings could be achieved by:
  - Decentralizing electricity generation by moving some renewable generation behind the meter, paired with battery storage.
  - Anticipated reduction in costs of wind and solar generation, battery storage, and hydrogen production and storage.
- Technological innovation will also be needed to achieve net zero more affordably.

Optimizing the diversified scenario requires integrated gas and electric system planning.

Recommended actions

RECOMMENDED ACTIONS

Four “safe-bet” actions needed today to reach net zero:

Maximize energy efficiency

Reduce energy use.

Optimize and integrate energy system planning

Coordinate electric and gas system planning.

Invest in low-carbon gases

Transition to increasing amounts of RNG and hydrogen over time.

Utilize carbon capture and storage

Invest in CCS for heavy industry and blue hydrogen production.

Maximize energy efficiency

- Energy efficiency is essential to success for any pathway to net zero.
- Enbridge's demand side management (DSM) programs have helped customers save 31 billion m^3 of natural gas, representing a cumulative reduction of 58 MT between 1995 and 2021*.

Actions to support:

- Continue to support increasing cost-effective natural gas conservation in Ontario, balancing bill impacts with the level of savings pursued.
- Continue to coordinate DSM offerings with new federal, provincial or municipal government funding for energy efficiency and GHG reduction programming. Ensure new funding does not displace or duplicate existing programs and that delivery is coordinated where reasonably possible to the benefit of program participants.

*Enbridge 2021 Sustainability Report, pg. 26. https://www.enbridge.com/~/media/Enb/Documents/Reports/Sustainability%20Report%202021/Enbridge-SR-2021.pdf

Optimize and integrate energy system planning

- Integrate gas and electric system planning to maintain the reliability and resilience Ontarians expect.
  - Include municipally led energy and climate planning initiatives that are funded and the impacts are quantifiable.
- Hybrid heating demonstrates the integration of gas and electric systems behind the meter.
- Gas-fired generation transitioned to low-carbon fuels will provide redundancy for renewables.

Actions to support:

- Model multiple diversified pathways as part of Ontario's Energy Transition Panel work.
- Encourage gas and electric planners to work together on long-term (20 yr.) demand scenario.
- Keep electric system low emissions, encourage the integration of renewables with storage and low carbon gases.
- Analyze the impact of wind power in Ontario.
- Develop regulatory structures that measure and value energy system resilience and require consideration of resilience.

Invest in low-carbon gases

- Hydrogen and RNG play a role in both pathways, particularly in the industrial sector.
- Ontario needs to invest now in the production of hydrogen and RNG to build and develop a market within the province while supporting the decarbonization of industry, heat, transportation and the gas system.
- Investing in hydrogen supports industrial decarbonization through hydrogen hubs and blending in the gas system to build scale within the market and reduce electrolyser costs for hydrogen production.

Actions to support:

- Define medium-term (2030) and long-term (2045) planning targets for RNG and hydrogen production.
- Investigate market measures and incentives that support RNG and hydrogen adoption.
- Expand the regulatory oversight of the Ontario Energy Board (OEB) to include a hydrogen regulatory framework.
- OEB must allow utilities to recover the cost of RNG and hydrogen at a different cost than natural gas and in line with the market price of these gases.

Utilize carbon capture & storage (CCS)

- CCS is needed to produce low-carbon hydrogen and to decarbonize hard-to-abate industrial processes and natural-gas fired electricity generation.

Actions to support:

- Amend regulations to enable geological sequestration of carbon dioxide, including the Oil, Gas and Salt Resources Act and the Mining Act.
- Enact a process for land rights acquisition to enable access to large blocks of subsurface pore space.
- Develop a regulatory framework for the approval of CCS projects.

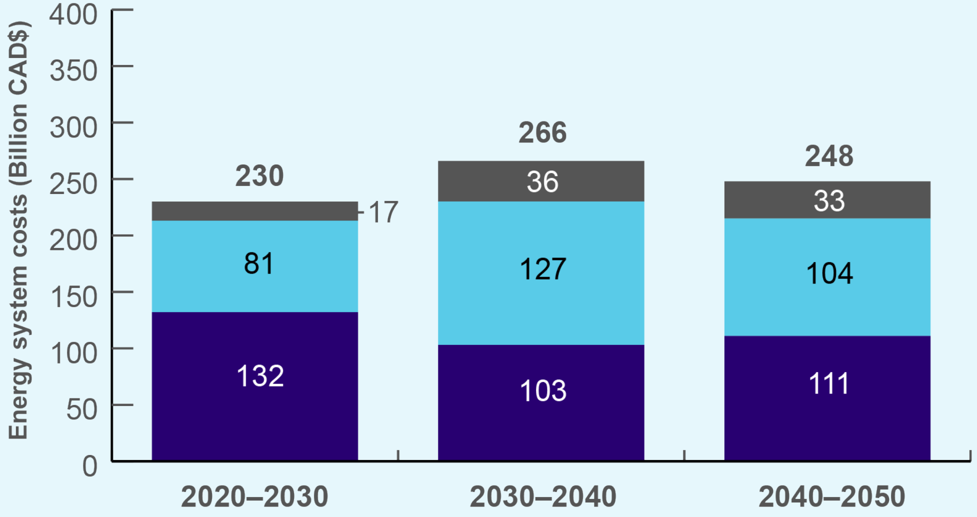
Q&A / Appendix

Cost Implications

Diversified scenario

- Gas System costs increase over time driven by the costs of deploying and operating new hydrogen and RNG production facilities, as well as adapting gas infrastructure to support increased hydrogen and RNG.
- Electricity system requires less new capacity required, driven primarily by investment in wind and solar capacity, transmission infrastructure.
- End user costs lower: Avoids need for building upgrades but increases over time as the adoption of heat pumps grow alongside investments in building retrofits and insulation.

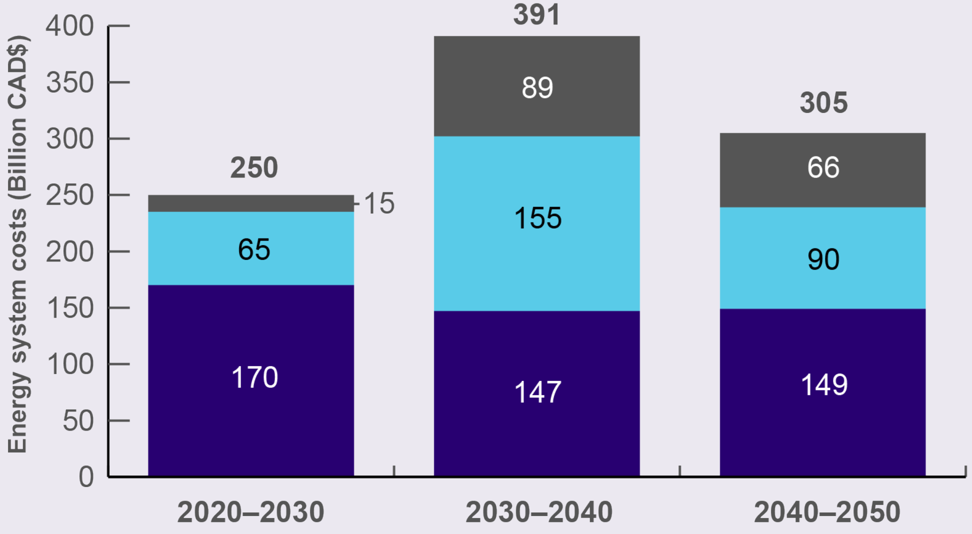
Diversified total cost: $744 billion



Electrification scenario

- Gas system costs higher reflecting continued use of natural gas through middle decades and increasing carbon price.
- Electricity system costs higher driven by higher peak demand (94GW) and required infrastructure to support.
- End users cost higher due to higher penetration of electric heat pumps and need for increased building retrofits to maintain home comfort.

Electrification total cost: $946 billion



Electricity System   Natural Gas System   End User Costs

Renewable Natural Gas

2024 OEB Rate Rebasing Application

October 2022

Overview

- OEB requires Enbridge Gas and other utilities to bring a cost of service application every 5 years to "rebase" or reset rates
- Enbridge Gas last filed for cost of service rates in 2013 and had a deferred rebasing period (2019-23) due to the amalgamation of EGD and Union Gas
- Enbridge Gas will be filing this month for new rates effective Jan 1, 2024 and a price cap formula for 2025-28
- Key themes include:
  - Increase in cost to serve customers in 2024
  - Harmonization of services, costs and rates
  - Energy Transition considerations and initiatives

Blending Renewable Natural Gas

- RNG is created from processing existing waste, such as waste from food, agricultural or landfill sources. This waste is recovered, broken down using anerobic digestion and upgraded into RNG.
- This gas can be added to existing natural gas infrastructure and is a one-for-one replacement of conventional natural gas.
- Enbridge Gas is looking to evolve the current RNG program to make it easier for more customers to consume greater quantities of low carbon energy.
- Enbridge Gas has taken steps to work towards incorporating energy transition in the gas supply commodity portfolio via the proposed Low Carbon Voluntary Program (LCVP) and the current Voluntary Renewable Natural Gas (VRNG).
- RNG, being carbon neutral, and exempt from the Federal Carbon Charge, is one of the best ways to lower GHG emissions affordably.

Low Carbon Voluntary Program

- We will be seeking to increase our low carbon energy in system supply beginning with 1% in 2025 and increasing by one percent per year until reaching 4% by 2028 with two mechanisms for cost recovery.
  - LCVP – will offer a customizable program to large volume sales service customers to upgrade a portion of their supply to RNG.
  - Incorporate the costs and benefits of low carbon energy that are not covered in the LCVP in the commodity reference price to have costs recovered as part of all system supply.

Benefits of a Blend

- Accessing made-in-Ontario RNG supply as soon as possible will allow the environmental benefits of RNG to remain in province and ensure Ontarians have access to the most economic supply of RNG while supply is still available. The longer Ontario waits, the higher the price we will be subject to.
- To give both large volume and small volume customers the best access to cost-effective RNG supply, Enbridge Gas is aligning the RNG demand of these two types of customers with the proposed program and can seek cost-effective long term RNG contracts.
- RNG displacing conventional natural gas creates Clean Fuel Regulation Credits. The value of these credits is still developing as that market begins to become more active. Enbridge Gas envisions that the value of these credits generated will be streamed to customers to reduce the cost of RNG.

Environmental and Economical Benefits

- If we have ~40 projects to meet the supply needed in 2030 we'd have up to 1000 full-time jobs after development of the project, creating significant economical benefits.
- An RNG blend of 4% by 2028 will meet 6% of the government of Ontario's GHG emissions reduction goal with this alone.
  - The emissions reductions would be equivalent to removing 230,000 gas-powered vehicles from the road for one year.
  - Over 50% of Enbridge's customers supported a blend of up to 5% RNG in our 2022 customer engagement.

Appendix

ENBRIDGE
Life Takes Energy

RNG Forecast Bill Impacts

RNG Blend Increase Costs for Average Residential Customer

RNG Bill Impacts	Blend :	Cumulative Annual Bill Increase	Monthly Bill Increase Excluding FCC Impact	Cumulative Increase Over July 2022 Average Bill	Year over Year Increase
2025	1.0%	$ 22.91	$ 1.91	1.840%	1.84%
2026	2.0%	$ 45.92	$ 3.83	3.688%	1.85%
2027	3.0%	$ 68.93	$ 5.74	5.536%	1.85%
2028	4.0%	$ 91.94	$ 7.66	7.385%	1.85%

RNG Blend Increase Costs for Average Residential Customer with Carbon Charge Reduction

RNG Bill Impacts	Blend :	Cumulative Annual Bill Increase	Monthly Bill Increase Including FCC Reduction	Cumulative Increase Over July 2022 Average Bill	Year over Year Increase
2025	1.0%	$ 18.33	$ 1.53	1.472%	1.47%
2026	2.0%	$ 35.27	$ 2.94	2.833%	1.36%
2027	3.0%	$ 50.77	$ 4.23	4.078%	1.25%
2028	4.0%	$ 64.82	$ 5.40	5.207%	1.13%

These bill impacts are only if there is no voluntary pickup from large volume customers, Enbridge doesn’t believe this will be the case. Enbridge will seek to place a cap of $2/month per percentage of RNG in the supply portfolio for average residential customers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2

Question(s):

Please provide a complete list of all consulting/legal reports produced to support this Application. Please indicate if all of those reports have been included with the pre-filed evidence. Please file all of the Terms of Reference for each of those engagements. Please file those that have not been included with the pre-filed evidence. For each engagement, please indicate whether the work was retained through an RFP process. If not, please explain why not. Please set out the total costs expected for each of those engagements and indicate how those costs will be recovered.

Response:

Please see Attachment 1 for details on all of the consulting reports produced to support Enbridge Gas's requests in Phase 1. These reports are all included in pre-filed evidence.

Attachment 2 contains Terms of Reference for each of these engagements parts of which have been redacted for reasons set out in the Company's accompanying request for confidential treatment of certain information filed in this proceeding.

Costs have been expensed as incurred between 2019 to 2023, with the exception of the costs of studies included in Exhibit 1, Tab 10, Schedule 5, which are being recovered through the EGD and Union Gas Greenhouse Gas Emissions Administration Deferral Accounts[1]. Cost details are included in Attachment 1.

[1] $10,000 of the costs of the studies in Exhibit 1, Tab 10, Schedule 5 were related to rebasing and were therefore expensed as incurred.

Phase 1 Third-Party Reports

Report Name	Consultant	Author Name	Evidence Reference	RFP	Why not?	How are Costs Allocated?	Total Costs
Energy Transition Scenario Analysis	Posterity Group Consulting	Alex Tiessen, Erika Aruja, David Shipley	Exhibit 1, Tab 10, Schedule 5, Attachment 1	N	An RFP process was not used for the ETSA report as Enbridge Gas was able to leverage work Posterity Group had already completed with other internal departments rather than duplicating work.	GGEADA (9900 O&M)	$ 297,850.00
Pathways to Net Zero Emissions for Ontario	Guidehouse Inc.	Nicola Charles, Decker Ringo, Alvaro Lara, Marissa Moultak, David Mavins, and Andrea Roszell	Exhibit 1, Tab 10, Schedule 5, Attachment 2	Y		GGEADA	$ 320,259.50
Energy Transition Scenario Analysis - ETI	Posterity Group Consulting	Alex Tiessen, Erika Aruja, David Shipley	Exhibit 1, Tab 10, Schedule 6, Attachment 1	N	The ETI report developed by Posterity Group was not retained through an RFP as it was an extension of the ETSA Report also developed by Posterity Group, and the same model was required to compare the scenarios in the ETSA report to the scenario in the ETI report.	O&M	$ 52,000.00
Assessment of the Future Utilization of the Enbridge Gas Dawn to Parkway System	ICF Resources, LLC	Michael Sloan, Andrew Griffith	Exhibit 1, Tab 11, Schedule 1, Attachment 1	N	An RFP was not used as this work is a continuation of analysis previously completed by ICF, ICF is also recognized as a subject matter expert with considerable knowledge in this area.	O&M	$ 24,000.00
Enbridge Gas 2024 Rate Rebasing Customer Engagement	Innovative Research Group, Inc.	Greg Lyle, Susan Oakes	Exhibit 1, Tab 6, Schedule 1, Attachment 1	Y		O&M	$ 376,896.50
Enbridge Gas Inc: Overhead Capitalization Study	Ernst & Young LLP (EY)	Abbas Lakha, Andrew Grainger	Exhibit 2, Tab 4, Schedule 2, Attachment 1	N	Enbridge Gas had an exisiting consulting agreement with E&Y, this work was completed under that agreement.	O&M	$ 616,000.00
Natural Gas Volume Forecasting Benchmarking Study	Guidehouse Inc.	Peter Steele-Mosey	Exhibit 3, Tab 2, Schedule 2	Y		O&M	$ 99,000.00
Approaches to Gas Design Day	Guidehouse Inc.	Andrea Roszell	Exhibit 4, Tab 2, Schedule 3, Attachment 1	Y		O&M	$ 105,000.00
EGI Pension and Benefit Plans Estimated 2022-2024 Net Periodic Benefit Costs	Mercer	Scott Thompson, Edith Samuels, Jesse Little, Ken Chin	Exhibit 4, Tab 4, Schedule 2, Attachment 1	N	As Enbridge Inc.'s actuary, Mercer does all the valuations.	O&M	$ 402,808.00
Compensation Benchmarking Review Enbridge Gas Inc.	Mercer	Kenneth Yung	Exhibit 4, Tab 4, Schedule 3, Attachment 1	N	As one of Enbridge's primary compensation consultants, Mercer was approached to assist with this work.	O&M	$ 107,145.00
ENBRIDGE GAS INC. PENSION, SAVINGS AND BENEFITS PROGRAMS BENCHMARKING	Willis Towers Watson	Randy Colbert	Exhibit 4, Tab 4, Schedule 3, Attachment 2	N	WTW has provided benchmarking analysis in the past, for both UG and EGD, and having a consistent methodology over time is desirable. As such, we did not entertain alternate proposals.	O&M	$ 39,600.00
Enbridge Gas Inc. Central Functions Cost Allocation Methodology Review	Guidehouse Inc.	Craig Sabine, Mernaz Malozewski	Exhibit 4, Tab 4, Schedule 3, Attachment 3	Y		O&M	$ 405,928.00
2021 DEPRECIATION STUDY	Concentric Advisors, ULC	Larry Kennedy, Amanda Nori	Exhibit 4, Tab 5, Schedule 1, Attachment 1	Y		O&M	$ 390,085.00
ENBRIDGE GAS INC. COMMON EQUITY RATIO STUDY	Concentric Advisors, ULC	James M. Coyne, Daniel S. Dane	Exhibit 5, Tab 3, Schedule 1, Attachment 1	N	Enbridge Gas's view is that Concentric was uniquely positioned to act on its behalf in this manner because of their extensive experience in other juristrictions on Equity thickness and ROE. They have also produced expert evidence in the past on behalf of Enbridge Gas.	O&M	$ 397,650.67
						Phase 1 Total	$ 3,634,222.67

June 3, 2021

Karen Sweet
Customer & Market Insights
Enbridge Gas Inc.

RE: Customer Engagement – Phase One Statement of Work

Dear Karen,

On behalf of Innovative Research Group Inc. (INNOVATIVE), I would like to thank you for the opportunity to work with Enbridge Gas Inc. (Enbridge) to conduct Phase One of the 2024 Rate Rebasing Customer Engagement.

As per our discussions, INNOVATIVE is being engaged to conduct a study as per the Terms of Project on the following page.

Once you have signed and returned this **Statement of Work**, INNOVATIVE will commence the work on this project.

We are looking forward to working with you. Once you have reviewed this letter, please sign and return to my attention. If you have any questions, please feel free to contact me at 416-642-6341.

Yours truly,

Susan Oakes
Vice President
Innovative Research Group Inc.
56 The Esplanade, Suite 310
Toronto, Ontario M5E 1A7

E-mail: soakes@innovativeresearch.ca

Qualitative Research

This is the development phase of the customer engagement program where we give customers an opportunity to identify key issues that they feel Enbridge needs to address.

Online Focus Groups with Residential Customers

Project Scope:

- Semi-structured discussions based on a written discussion guide
- 6-8 participants per session
- A total of 10 focus groups to provide regional and legacy coverage (see list below)
- All participants receive a monetary incentive of $100 for participating

Group Descriptions

Group	Region	Number
LUG North	Northern	2
LUG Central / East	Hamilton/Halton, Eastern	2
LUG South / West	Windsor/Chatham, London/Sarnia, Waterloo/Brantford	2
LEG GTA	Toronto (1), Central West (21) Central East (45 and 35)	2
LEG Other	Eastern (65), Niagara (76) Central West (53), Central East (47)	2

Focus group costs include project management, the finalization of the recruitment screener and moderator's guide, a combination of online and telephone recruitment of all participants, incentives, moderating, research consultant support and a report based on the research.

We will conduct two groups per evening, over a total of five evenings. The cost per evening is [redacted] bringing the total budget for the focus groups to [redacted]

IDIs with Small and Medium-Large Commercial Customers

Project Scope:

- Semi-structured discussions based on a written discussion guide
- A total of 20 interviews, divided evenly between small and med-lg customers
- The interviews will also be evenly divided between LUG and LEG customers
- A charitable donation in the amount of $100 will be made on behalf of each participant

Costs include project management, the finalization of the recruitment screener and interview guide, a combination of online and telephone recruitment of all participants, incentives (charitable donations), interviews by senior consultants (Susan Oakes and Julian Garas), and a report based on the research.

The total cost for the in-depth interviews is [redacted]

Total Phase One Project Costs

[redacted] + HST

- Invoice 1 of 2 (50%) upon project commencement
- Invoice 2 of 2 (50%) upon receipt of final report

July 22, 2021

Karen Sweet
Customer & Market Insights
Enbridge Gas Inc.

RE: Customer Engagement – Phase Two Statement of Work [REVISED]

Dear Karen,

On behalf of Innovative Research Group Inc. (INNOVATIVE), I would like to thank you for the opportunity to work with Enbridge Gas Inc. (Enbridge) to conduct Phase Two of the 2024 Rate Rebasing Customer Engagement.

As per our discussions, INNOVATIVE is being engaged to conduct a study as per the Terms of Project on the following page.

Once you have approved this **Statement of Work**, INNOVATIVE will commence the work on this project.

We are looking forward to working with you. Once you have reviewed this letter, please send me an email with approval to proceed. If you have any questions, please feel free to contact me at 416-642-6341.

Yours truly,

Susan Oakes
Vice President
Innovative Research Group Inc.
56 The Esplanade, Suite 310
Toronto, Ontario M5E 1A7

E-mail: soakes@innovativeresearch.ca

Phase Two is the Refinement phase, and will involve surveys with residential customers, as well as small and medium-large commercial / industrial customers. INNOVATIVE will provide two reports for this phase: one for residential customers and one for commercial / industrial customers. Per our proposal, we have assumed in all cases Enbridge research staff will provide initial drafts of the surveys.

Residential Customers

With residential customers, we will conduct an online survey of 2,400 which will ensure representation across rate zones and regions. We will also conduct a telephone survey of 600 residential customers, with a regional distribution that is reflective of actual distribution across the province. The cost for telephone set-up assumes we are adjusting from the online survey. Demographic questions within the survey will allow us to identify low-income customers and other important customer segments for analysis purposes.

This budget is based on the current version of the survey, which is at 60 questions for residential customers. Note that open-ended questions are counted as three questions due to the extra time involved in coding verbatim responses.

Please note that we are not including incentives for residential customers.

Cost Breakdown	Online (n=2,400)	Telephone (n=600)
Set-up/platform	[redacted]	[redacted]
Data collection	[redacted]	[redacted]
Analysis and reporting	[redacted]	[redacted]
TOTAL:	[redacted]	[redacted]

Commercial / Industrial Customers

For the commercial and industrial customers, we will use a mixed methodology of online and telephone surveys. Customers will first be sent an email inviting them to complete an online survey, and reminders will encourage participation from those who don't respond initially. Depending on response rate, we will supplement with telephone interviews in order to arrive at a final sample of 200 small C/I customers and 200 Med-Large C/I customers.

The surveys will be identical with only slight adjustments in the language to accommodate the differences in methodology. *This budget is based on the current version of the survey, which is at 61 questions for commercial customers. Note that open-ended questions are counted as three questions due to the extra time involved in coding verbatim responses*. The telephone survey will include some questions to ensure we are directed to the most appropriate person.

Cost Breakdown	Online	Telephone
Set-up/platform	[redacted]	[redacted]
Analysis and reporting	[redacted]	
TOTAL FIXED COST:	[redacted]	[redacted]
CPI	[redacted]	[redacted]
Incentives (400 x $15+$350 admin)	[redacted]	[redacted]

Total Phase Two Project Costs

The total cost for Phase Two will depend on the number of interviews completed by phone with C/I customers vs the number completed online. The lowest and highest points of the range of total costs are shown below.

	Lowest Range (all C/I interviews completed online)	**Highest Range** (all C/I interviews completed by telephone)
Residential customers: online	[redacted]	[redacted]
Residential customers: telephone	[redacted]	[redacted]
Small & Med-Large C/I customers	[redacted]	[redacted]
Incentives	[redacted]	[redacted]
TOTAL:	[redacted]	[redacted]

- Invoice 1 of 2 (50% of lowest range cost) upon project commencement
- Invoice 2 of 2 (remaining cost based on mix of telephone and online C/I completes) upon receipt of final report

October 6, 2021

Karen Sweet
Customer & Market Insights
Enbridge Gas Inc.

RE: Customer Engagement – Phase Three Statement of Work

Dear Karen,

On behalf of Innovative Research Group Inc. (INNOVATIVE), I would like to thank you for the opportunity to work with Enbridge Gas Inc. (Enbridge) to conduct Phase Three of the 2024 Rate Rebasing Customer Engagement.

As per our discussions, INNOVATIVE is being engaged to conduct a study as per the Terms of Project on the following page.

Once you have approved this **Statement of Work**, INNOVATIVE will commence the work on this project.

We are looking forward to working with you. Once you have reviewed this letter, please send me an email with approval to proceed. If you have any questions, please feel free to contact me at 416-642-6341.

Yours truly,

Susan Oakes
Vice President
Innovative Research Group Inc.
56 The Esplanade, Suite 310
Toronto, Ontario M5E 1A7

E-mail: soakes@innovativeresearch.ca

Phase Three is the validation phase is where we obtain results that can be generalized across the various customer segments. As with Phase Two, Enbridge Gas will provide draft workbook-style surveys for this phase. INNOVATIVE will provide suggested edits to these surveys based on our previous experience as well as what we learned in the first two phases of the engagement.

Greg Lyle and Susan Oakes will work with Enbridge Gas to finalize the workbook. Time spent on workbook design and development will be charged at an hourly rate of $350 for Greg and $300 for Susan.

Methodology Options in RFQ vs Final Planned Engagement

The original RFQ specified engagement options for each customer segment for Phase Three. The final planned engagement activities differ and the length of the survey is more likely to be in the range of 25 minutes than 15 minutes, so the budget has been adjusted to accurately reflect the final planned approach. Based on our experience, we are basing all budget estimates on a survey that includes 50 closed and 10 open-ended questions. The final budget will be adjusted to reflect the actual number and type of questions.

In addition to the change in the length of the survey, it will be necessary to use a workbook format in order to effectively engage customers and allow them to give more informed opinions. Programming these workbooks is significantly more time-consuming than programming a standard survey. We are also adding workbook testing, with a broad enough scope to give us some directional notion of where the numbers are heading in advance of a full launch.

Customer Segments	Options in RFQ	Final Planned Engagement
Residential	Telephone – 1,800 interviews Online – 1,800 interviews; OR Consider an open link survey invitation shared via bill insert / myaccount	• Representative online workbook-style survey – n=7,200 • Openlink survey • No telephone survey
General Service / Small Commercial	Online – 400 Telephone – 400 (depending on online response)	• Online survey with invitations sent to all available sample • No telephone survey
Medium – Large Commercial / Industrial (Billed)	Online – invitation to participate sent to all (assume n=100) Telephone – 200 (depending on online response)	• Online survey with invitations sent to all available sample • No telephone survey
Commercial / Industrial (Contract)	Online – invitation to participate sent to all (assume n=100)	Online survey with invitations sent to all available sample
Strategic (Large Volume Commercial)	Online – invitation to participate sent to all (assume n=30)	Online survey with invitations sent to all available sample
Transportation	N/A – contact with these customers will most likely be an internal effort Consider set of validation interviews (5-10 min in length); OR Online – invitation to participate sent to all (assume n=30)	• Telephone validation interviews • No online survey

Workbook Testing

The final report will focus on this phase, so it is critical to ensure we are asking the right questions and providing the right information to customers in a manner that is easy to understand. To that end, we strongly recommend that senior INNOVATIVE consultants test the workbook with the target customer segments prior to the start of any data collection.

The workbook will be tested with various customer segments in a series of one-on-one interviews using Zoom. During each session, the facilitator will give control of his/her computer to the customer and ask them to work their way through the workbook, responding to the survey questions as they go. The facilitator will ask the customer if there are any issues with clarity as they progress through the workbook, and at the end of the session there will be an opportunity for the customer to comment on the amount and type of information provided, and whether they felt anything was missing.

For this type of testing, the workbook will need to be programmed to make it as realistic an experience as possible. The actual cost for programming will depend on the length and complexity of the workbooks, as well as the degree to which the Contract workbook is similar to the General Service workbook. To give a sense of what the programming may cost, we have developed the following budget estimates based on our experience with large electrical utilities, and we have assumed that the Contract workbook is about 75% the same as the GS version.

WORKBOOK VERSION	ESTIMATED # OF HOURS	HOURLY RATE	TOTAL
Residential	60	[redacted]	[redacted]
Small/med-large business*	15	[redacted]	[redacted]
Commercial/industrial (contract)	15	[redacted]	[redacted]
		TOTAL:	[redacted]

** Assumes minor changes, such as changes to rate impacts and "home" vs "business"*

As long as no major programming changes are required, adjustments can be made as the testing progresses to incorporate customer feedback, with the goal of optimizing the workbook prior to rolling it out to all customers.

The final amount charged for programming will be based on the actual number of hours required to program and make adjustments to all versions of the workbook.

CUSTOMER SEGMENT	NUMBER OF INTERVIEWS	COST PER INTERVIEW	INCENTIVE*	TOTAL
Residential	20	[redacted]	$100	[redacted]
Small business	15	[redacted]	$150	[redacted]
Commercial/industrial (contract)	5	[redacted]	$150	[redacted]
			TOTAL:	[redacted]

** In recognition of the fact that some organizations have policies against accepting gifts or cash, incentives for business customers will be offered as either a direct incentive to the individual, or in the form of a donation to a charity of their choosing.*

General Service Workbook

For residential customers, there will be an invitation-based online survey for which the sample will be stratified based on region/legacy and consumption in order to arrive at a final sample that is representative of that customer group. Based on the incidence of LEAP qualified customers in Phase Two, it is estimated that a total sample of 7,200 will garner about n=400 completes from residential customers who qualify for the LEAP program.

Invitations will also be sent to all small and medium-large business customers who did not participate in either Phase One or Phase Two of the customer engagement. The goal will to be obtain as many completes as possible from these customers, so there will be no sample stratification. However, we will include region/legacy and consumption as sample variables and use that information to weight the final data to be representative. It should be noted that we may have to weight the sample size down significantly to arrive at a representative sample because we want to avoid using weights any higher than 2.

A voluntary, openlink survey will also be publicized by Enbridge Gas to residential customers to ensure that all residential customers have a chance to take part in the customer engagement. The reporting on the representative vs openlink data can be done separately (costs are broken out below), or we may be able to create a hybrid report to keep costs down.

The budget below is based on a survey that is comprised of 50 closed and 10 open-ended questions. The final number of open-ended questions will impact the budget due to the time needed to code verbatim responses.

In order to keep the budget down, we would suggest coding all of the residential representative survey verbatims, and a random selection of no more than 2,500 verbatims from the openlink version of the survey at a cost o[redacted] per question.

Please note that we are not including incentives for residential customers. For business customers, we recommend two prize draws of $500 for small business and two prize draws of $500 for med/lg business.

COST BREAKDOWN	COST
Set-up/platform	[redacted]
Data collection	[redacted]
Incentives & facilitation	[redacted]
Analysis and reporting:	
Residential representative	[redacted]
Residential openlink	[redacted]
GS business	[redacted]
TOTAL:	[redacted]

Contract Customers

All Enbridge Gas Contract customers (as well as about 30 Strategic customers) will be sent an invitation with a unique link to an online workbook survey. Where possible, the workbook will be similar to the General Service version, but there will be differences due to the specific nature of this customer segment. We have provided a cost for creating a separate report for this customer segment.

The budget below is based on a survey that is comprised of 50 closed and 10 open-ended questions. The final number of open-ended questions will impact the budget due to the time needed to code verbatim responses.

For contract customers, we recommend two prize draws of $500.

COST BREAKDOWN	COST
Set-up/platform	[redacted]
Data collection	[redacted]
Incentives & fulfillment	[redacted]
Analysis and reporting	[redacted]
TOTAL:	[redacted]

Transportation Customers

Enbridge Gas will engage with Transportation customers directly. INNOVATIVE will follow-up with a brief, 5-minute telephone survey. The goal of the survey will be to confirm that the customer spoke with Enbridge Gas, that key topics were covered, and that they understood the information that was provided to them.

There are about 30 customers in this rate class, and INNOVATIVE will make all reasonable attempts to follow-up with each customer once Enbridge Gas has spoken with them. The total budget for this aspect of the consultation, including reporting, is set out below.

COST BREAKDOWN	COST
Data collection	[redacted]
Analysis and reporting	[redacted]
TOTAL:	[redacted]

Total Phase Three Project Costs

The total costs for Phase Three are set out below.

The two variable costs are the professional fees for workbook development and programming.

- Time spent on workbook design and development will be charged at an hourly rate of [redacted] for Greg and [redacted] for Susan. ***These hours are not included in the budget summary below.***
- The final amount charged for workbook programming will be based on the actual number of hours, at an hourly rate of [redacted]

ENGAGEMENT COMPONENT	COST
Programming	[redacted]
Workbook testing	[redacted]
General service workbook	[redacted]
Contract workbook	[redacted]
Transport validation interviews	[redacted]
TOTAL:	[redacted]

- Invoice 1 of 2 upon project commencement
- Invoice 2 of 2 upon receipt of final report

May 31, 2022

Karen Sweet
Customer & Market Insights
Enbridge Gas Inc.

RE: Rate Rebasing – Qualitative Customer Engagement

Dear Karen,

On behalf of Innovative Research Group Inc. (INNOVATIVE), I would like to thank you for the opportunity to work once again with Enbridge Gas Inc. (Enbridge) to conduct an additional round of qualitative research as part of the 2024 Rate Rebasing Customer Engagement.

As per our discussions, INNOVATIVE is being engaged to conduct a study as per the Terms of Project on the following page.

Once you have signed and returned this **Statement of Work**, INNOVATIVE will commence the work on this project.

We are looking forward to working with you. Once you have reviewed this letter, please sign and return to my attention. If you have any questions, please feel free to contact me at 416-642-6341.

Yours truly,

Susan Oakes
Vice President
Innovative Research Group Inc.
56 The Esplanade, Suite 310
Toronto, Ontario M5E 1A7

E-mail: soakes@innovativeresearch.ca

Qualitative Research

This follow-up round of qualitative research will build on what we learned in all three phases of the comprehensive 2024 Rate Rebasing Customer Engagement. The objectives of this round of qualitative research will be to:

- Understand how customer distinguish between fixed and variable costs (incurred by Enbridge Gas) of providing service.
- Further explore how customers think about rate design:
  - What do customers consider as their usage – consider annual vs. daily
  - How to do customers understand the differing costs of being connected to the system and cost of system capacity
  - How do customers view the cost of gas – and how do they relate it to the usage in their home or business
- Participants will also be presented with various bill presentment options, including a mock-up of a new sample bill.

Online Focus Groups with Residential Customers

Project Scope:

- Semi-structured discussions based on a written discussion guide
- 6-8 participants per session
- One evening (two groups) which will serve as a testing phase and will not be included in the final report, but will serve instead to finalize stimuli and the moderator's guide
- Following the testing and any resulting revisions, a total of 10 online focus groups to provide regional coverage (see list below)
- All participants receive a monetary incentive of $100 for participating

Group Descriptions

Group	Region	Number
Enbridge Gas	GTA	*2*
Enbridge Gas	Non-GTA	*2*
Union Gas	South/West	*2*
Union Gas	Central	*2*
Union Gas	North/East	*2*

When designing the recruitment screeners, additional factors will be taken into consideration both to ensure representation across a range of customers, as well as potentially recruiting such that certain types of customers are not in the same group. This may included things such as:

- Screening for Hydro One (primarily non-GTA) or Toronto Hydro (GTA) customers
- Paper vs ebill customers
- Level of attention paid to bills
- Consumption level

Focus group costs include project management, the finalization of the recruitment screener and moderator's guide, a combination of online and telephone recruitment of all participants, incentives, moderating, research consultant support and a report based on the research.

We will conduct two groups per evening, over a total of five evenings. The cost per evening is [redacted] bringing the total budget for the focus groups to [redacted]

IDIs with Small and Medium-Large Commercial Customers

Project Scope:

- Semi-structured discussions based on a written discussion guide
- A total of 20 interviews, divided evenly between small and med-lg customers
- The interviews will also be evenly divided between EGI and former Union Gas customers
- A charitable donation in the amount of $100 will be made on behalf of each participant

Costs include project management, the finalization of the recruitment screener and interview guide, a combination of online and telephone recruitment of all participants, incentives (charitable donations), interviews by senior consultants, and a report based on the research.

The total cost for the in-depth interviews is [redacted]

Total Project Costs

Fixed Cost: [redacted] **HST**

- Invoice 1 of 2 (50%) upon project commencement
- Invoice 2 of 2 (50%) upon receipt of final report

Variable Design and Development Cost: The extent to which INNOVATIVE will be involved in designing and developing stimulus and other materials to be used during the groups/interviews is not known at this point. As such, time spent on such activities will be billed at a rate of [redacted] per hour.

ENBRIDGE

50 Keil Drive North, Box 2001
Chatham ON N7M 5M1

Sophear Net, Specialist BD
Tel: 519-436-4600 ext. 5002394
Email: sophear.net@enbridge.com

July 20, 2020

POSTERITY GROUP CONSULTING INC.
43 Eccles Street, Unit 2 – Second Floor
Ottawa Ontario K1R 6S3

Dear Sir / Madam,

RE: Consulting Agreement with Enbridge Gas Inc.

Attached please find for signature our Consulting Agreement. Kindly arrange to have the Agreement and the attached Schedule signed. Please ensure you read and understand all of the terms and conditions of the Agreement, as well as the enclosed Statement on Business Conduct and Lifesaving Rules.

We will also require the following:

- A current clearance certificate or letter of exemption from the Ontario Workplace Safety and Insurance Board ("WSIB"). If your employees are in a jurisdiction other than Ontario, please provide equivalent proof of coverage, and new proof of coverage must be filed with us upon expiry/renewal of such proof of coverage.

Please return the applicable WSIB document noted above, together with a signed copy of the Consulting Agreement and a signed copy of the Schedule, promptly following receipt of this letter. Upon receipt of all the documents in our office, we will execute the Agreement and a PDF copy of the Agreement will be returned to you for your records.

If you have any questions, please contact me at the above-noted telephone number.

Sincerely,

Sophear Net
Specialist BD

Encls.

CONSULTING AGREEMENT

THIS AGREEMENT made effective July 20, 2020.

B E T W E E N:

ENBRIDGE GAS INC.
("Enbridge")

- and -

POSTERITY GROUP CONSULTING INC.
(the "Consultant")

WITNESSES THAT in consideration of the mutual covenants and agreements herein contained, the parties hereto covenant and agree as follows:

1. **Scope of Services**

(a) During the term hereof (as hereinafter defined), the Consultant shall provide consulting services (the "Services") to Enbridge, on the terms and conditions set forth below.

(b) The scope of work for specific projects to be undertaken by the Consultant at the request of Enbridge will be described in separate schedules referencing this Agreement, each of which shall become effective, be incorporated by reference and form an integral part of this Agreement upon the execution of each such schedule by Enbridge and the Consultant. The schedule for each project will specify the names of key individuals, scope of Services, deliverables, commencement and completion dates, rate of compensation and payment terms applicable to such project. Each schedule described above shall be prepared using a form similar to the attached Schedule "A".

2. **Compensation**

In consideration of the Services and deliverables to be provided by the Consultant hereunder, and provided that the Consultant is not in default of its obligations hereunder, Enbridge shall remit to the Consultant all amounts required to be paid in accordance with the applicable schedule.

Consultant shall be responsible for charging, collecting and remitting all applicable federal and provincial sales, use and value-added taxes in respect of the fees paid or payable to Consultant and, in particular, the goods and services tax ("GST") and harmonized sales tax ("HST") imposed under Part IX of the Excise Tax Act (the "ETA"), the Quebec sales tax ("QST") imposed under an Act respecting the Quebec Sales Tax (the "QSTA") and any provincial sales taxes ("PST"); and such taxes, if applicable, shall be shown separately on all invoices. Where Consultant is required to collect any GST/HST, QST or similar tax, Consultant shall provide Enbridge with the documentary evidence as prescribed pursuant to the ETA or QSTA, any successor provision thereto or any similar provision of any other taxing statute as is required to entitle Enbridge to claim an input tax credit, input tax refund, rebate, refund or any other form of relief in respect of such taxes.

Where the Consultant is a non-resident of Canada for purposes of the Income Tax Act (Canada) (the "ITA"), with respect to the invoice or statement of Fees issued pursuant to any Schedule, the Consultant will identify the location where the Services are provided, separate Services performed in Canada from Services performed outside of Canada, identify the number of days Services were performed in Canada (including travel days to/from Canada) and, for Services performed in Canada, identify the physical location, indicating city and province, where such Services were performed. Where the non-resident Consultant has not obtained and provided to Enbridge a non-resident withholding tax waiver at such time as Enbridge makes any payment to the Consultant for Services, Enbridge shall withhold such percentage

of any payment as mandated under the ITA with respect to the Services provided in Canada or on the full invoice or statement amount where the Consultant has not clearly separated the Services performed in Canada from Services performed outside of Canada. Enbridge shall remit the withheld amount to Canada Revenue Agency, or its successor, in the manner and at the time required by the ITA. For further clarification, it is the Consultant's responsibility to obtain the tax waiver, if available. In the event that Enbridge is assessed for any non-resident withholding taxes payable, the Consultant agrees to forthwith reimburse Enbridge for such amount together with applicable interest and penalties, if any.

3. **Term**

Subject to earlier termination as provided for herein, the term of this Agreement shall commence on the day set forth above and expire on July 19, 2023 (hereinafter the "Term").

4. **Termination**

(a) Enbridge may terminate this Agreement or any schedule to this Agreement for convenience upon giving two (2) weeks written notice to the Consultant.

(b) Either party may terminate this Agreement in case of a breach by the other party of its obligations hereunder, provided that the breach is not cured within five (5) days of written notification by the non-defaulting party to the defaulting party setting out the particulars of the breach.

(c) Either party may terminate this Agreement upon written notice to the other party, if: (i) the other party is subject to proceedings in bankruptcy, or insolvency, whether voluntary or involuntary, (ii) a receiver is appointed in respect of all or a substantial portion of the other party's assets; or (iii) the other party assigns its property to its creditors or generally becomes unable to pay its debts as they become due.

Upon any termination of this Agreement, the Consultant shall deliver to Enbridge the results of all Services provided as of the date of termination, including completed or uncompleted deliverables for which payment has been received in accordance with the terms of this Agreement.

5. **Facilities**

Enbridge shall provide to the Consultant use of such office facilities as may be required by the Consultant, acting reasonably, to perform the Services during the Term.

6. **Reimbursement for Expenses**

In addition to the payments to be made pursuant to Section 2 hereof, Enbridge shall reimburse the Consultant for all reasonable expenses properly incurred by the Consultant in connection with the Services provided to Enbridge hereunder and that have been pre-approved by Enbridge in writing, including, without limitation, reasonable travel and other costs and expenses in connection therewith. Such pre-approved reasonable expenses incurred by the Consultant in rendering Services shall be reimbursed by Enbridge net of GST/HST. GST/HST shall be charged, where applicable, by the Consultant on the expenses incurred, net of the input tax credits/reimbursements for GST/HST claimed by the Consultant. Concurrently with its delivery of invoices to Enbridge as contemplated by Section 2 hereof, the Consultant shall submit to Enbridge invoices and statements setting out in reasonable detail the nature and amount of the expenses or costs incurred by the Consultant for which the Consultant claims reimbursement, and Enbridge shall within thirty (30) days of the receipt of such invoices and statements reimburse the Consultant for all approved invoiced expenses and costs. The Consultant shall provide to Enbridge copies of all documentation in support of invoiced expenses as Enbridge may request from time to time during the Term hereof.

7. **Independent Contractor**

Notwithstanding anything to the contrary herein contained, the Consultant shall not, for any purpose, be or be deemed to be an employee of Enbridge during the Term or at any time during which the Services described in Section 1 hereof are provided to Enbridge nor shall anything in this Agreement create or be

construed for any purpose as creating any relationship between Enbridge and the Consultant of employer and employee. Except as expressly provided herein, Enbridge shall not be liable to contribute to any employee benefit or pension plan or pay premiums for any policy or form of insurance whatsoever on behalf of the Consultant nor to pay any amounts or premiums on its behalf in respect of the Canada Pension Plan, Ontario Health Insurance Plan, Workplace Safety and Insurance Board or Employment Insurance, nor to deduct or withhold from source any amount from amounts payable by Enbridge to the Consultant hereunder in respect of any income tax obligation or liability payable by the Consultant to the Canada Revenue Agency. The Consultant agrees to indemnify and hold Enbridge harmless from and against any order, penalty, interest or tax that may be assessed or levied against Enbridge as a result of the failure or delay of the Consultant to file any return or information required to be filed by the Consultant by any law, ordinance or regulation relating to the Services performed by the Consultant herein.

8. **Confidential Information and Personal Information**

(a) For the purposes of this Section 8, the following definitions will apply:

(i) "Confidential Information", means all information pertaining to the business and affairs of Enbridge, its affiliates and subsidiaries, whether oral or written, furnished by Enbridge to the Consultant, its employees and representatives, whether furnished or prepared before or after the date of this Agreement, and includes all analysis, compilations, data, studies, reports or other documents prepared by the Consultant based upon or including any of the information furnished by Enbridge, but does not include information which:

A. is at the time of disclosure or thereafter becomes generally available to the public other than as a result of disclosure by the Consultant or anyone to whom the Consultant transmits the information;

B. is at the time of disclosure or thereafter becomes known or available to the Consultant on a non-confidential basis and not in contravention of applicable law from a source other than Enbridge that is entitled to disclose the information; or

C. is already in the possession of the Consultant or is lawfully acquired, provided that such information is not subject to another confidentiality agreement with, or obligations of secrecy to Enbridge.

(ii) "Person" includes individuals, partnerships, firms and corporations.

(b) Enbridge is furnishing the Confidential Information to the Consultant solely for the purpose of assisting the Consultant in the performance of Services which the Consultant provides to Enbridge. The Consultant shall not use the Confidential Information for any purpose other than the performance of Services provided to Enbridge.

(c) The Consultant acknowledges that the Confidential Information is the property of Enbridge, which is confidential and material to the interests, business and affairs of Enbridge and that disclosure thereof would be detrimental to the interests, business and affairs of Enbridge. Accordingly, the Consultant agrees that it shall maintain the confidentiality of the Confidential Information and that it shall not disclose the Confidential Information to any Person for any reason whatsoever except as expressly provided herein.

(d) The Consultant may disclose Confidential Information to the extent required by a court of competent jurisdiction or other governmental or regulatory authority or otherwise as required by applicable law, provided that the Consultant first give Enbridge prompt written notice (except where the governmental or regulatory authority has expressly ordered that no notice be given) and co-operate with and assist Enbridge in responding to the request or demand for disclosure.

(e) The Consultant acknowledges and agrees that Enbridge would be irreparably harmed if any provision of this Agreement is not performed by the Consultant in accordance with its terms. Accordingly, Enbridge shall be entitled to an injunction or injunctions to prevent breaches of any of the provisions of this Agreement and may specifically enforce such provisions by an action

instituted in a court having jurisdiction. These specific remedies are in addition to any other remedy to which Enbridge may be entitled at law or equity.

(f) If in the course of performing Services hereunder, the Consultant obtains or accesses personal information about an individual, including without limitation, a customer, potential customer or employee or contractor of Enbridge ("Personal Information") the Consultant agrees to treat such Personal Information in compliance with all applicable federal or provincial privacy or protection of personal information laws and to use such Personal Information only for purposes of providing the Services hereunder. Furthermore, the Consultant acknowledges and agrees that it will:

(i) not otherwise copy, retain, use, modify, manipulate, disclose or make available any Personal Information, except as required by applicable law;

(ii) establish or maintain in place appropriate policies and procedures to protect Personal Information from unauthorized collection, use or disclosure;

(iii) implement such policies and procedures thoroughly and effectively;

(iv) except as required for purposes of providing the Services hereunder, will not develop or derive, for any purpose whatsoever, any products in machine-readable form or otherwise, that incorporates, modifies, or uses in any manner whatsoever, any Personal Information; and

(v) upon completion of its Services for or on behalf of Enbridge, will at Enbridge's direction: A. return; or B. destroy all Personal Information and all copies and records thereof in its possession.

9. Indemnification

The Consultant hereby agrees to and shall:

(a) be liable to Enbridge and its directors, officers and employees, for all claims, liabilities, damages, costs, losses and expenses whatsoever which Enbridge or any of its directors, officers and employees may suffer, sustain or incur; and

(b) indemnify and save harmless Enbridge, Enbridge's affiliated and subsidiary companies, and their directors, officers, agents, employees and representatives from and against any and all liabilities, claims, demands, damages, loss, costs and expenses (including without limitation all applicable solicitors' fees, court costs and disbursements, investigation expenses, adjusters' fees and disbursements) to or which any third party may suffer, sustain or incur,

in respect of all matters or anything which may arise out of any act or omission directly or indirectly related to any breach of this Agreement by the Consultant, its employees or representatives.

10. Work Product

(a) For the purposes of this Section 10, "Work Product" shall include any of the following, which are developed in the course of or arise from the Services provided by the Consultant to Enbridge hereunder throughout the Term: (i) any deliverables produced under any schedule to this Agreement together with any and all notes, reports, research information, compilations, data specifications, designs, programs, documentation, software (including object code and source materials), development tools, products and other materials or things; (ii) any and all knowledge, know-how, techniques, inventions, processes, trade secrets, methodologies, approaches and other intangible intellectual property rights; and (iii) all designs, patent applications, issued patents, industrial design registrations, design patents, trade-mark applications, registered trade-marks and copyright which may relate thereto.

(b) For the purposes of this Section 10, "Consultant Materials" comprises any of the following, which were developed by the Consultant, at its own cost and expense in advance of and independent of this Agreement and as proven by the Consultant to be the case in the event of a dispute concerning the same: (i) any and all notes, research, information, data, specifications, designs, programs, documentation, software (including object code and source materials), development tools, products and other materials or things; (ii) any and all knowledge, know-how, techniques, inventions, processes, trade secrets, methodologies, approaches and other intangible intellectual property rights; and (iii) all designs, patent applications, issued patents, industrial design registrations, design patents, trade-mark applications, registered trade-marks and copyright which may relate thereto.

(c) All right, title and interest in and to the Work Product shall be the property of Enbridge. The Consultant shall ensure that any agent or employee of the Consultant shall have waived in writing all of his or her moral rights over any such Intellectual Property. During and after the Term of this Agreement, the Consultant shall from time to time as and when requested by Enbridge execute all papers and documents and perform other acts as necessary or appropriate to evidence or further document Enbridge's ownership of the Work Product and the intellectual property rights therein.

(d) The Consultant retains all right, title and interest in and to the Consultant Materials. The Consultant hereby grants to Enbridge a non-exclusive, perpetual, irrevocable, non-terminable, transferable, assignable and royalty-free license to copy, disclose, use, operate, maintain, repair, modify, enhance, make derivative works, license, sub-license and otherwise commercially exploit without limitation or restriction those Consultant Materials used in connection with the delivery of the Services or to the extent contained within any Work Product.

(e) The Consultant agrees to fully indemnify and hold harmless Enbridge from and against any and all: (i) claims, demands and actions; (ii) liabilities, damages or losses awarded by a court of competent jurisdiction or as agreed to as part of a settlement; and (iii) litigation costs and/or expenses (including reasonable legal fees and disbursements) reasonably incurred by Enbridge in connection with any claim that the Services or Work Product provided hereunder infringe any patent, copyright, trade secret or other right of any third party.

11. **Representations and Warranties**

(a) The Consultant represents, warrants and covenants with Enbridge that: (i) it will perform all Services in a good and workmanlike manner using reasonable care (at a level that is at least consistent with industry standards for the provision of similar services) and in accordance with the terms of this Agreement; (ii) it possesses the knowledge, skill and experience necessary for the provision and completion of the Services in accordance with the terms of this Agreement; and (iii) any deliverables provided hereunder shall conform to their relevant specifications as described in the applicable schedule.

(b) The Consultant agrees that under no circumstances will it interface a non-Enbridge computing device (including without limitation desktops, laptops, handheld device) with the Enbridge intranet or internet without obtaining the prior written approval of Enbridge. To the extent the deliverables produced hereunder involve the provision or development of any software application, interface or electronic data, the Consultant shall use commercially reasonable efforts to prevent the introduction of any virus to the hardware and computer systems upon which the application, interface or electronic data are to be installed. During the Term of this Agreement, the Consultant shall implement and run virus prevention and detection control procedures in accordance with industry standards.

(c) In addition to the policies described in Section 25, the Consultant shall ensure that it is familiar with and understands all of Enbridge's current policies, procedures and standards that are pertinent to the activities associated with the Services and which have been provided to the Consultant in advance of the execution of this Agreement.

12. **Subcontractors**

The Consultant shall not enter into any agreement with any other party to assist in the provision of the Services described in Section 1 hereof (hereinafter described as a "Subcontract") nor shall the Consultant allow any other party to perform such Services or any part thereof without first obtaining the consent in writing of Enbridge, which consent may be withheld by Enbridge, acting reasonably. Notwithstanding any approval or consent that may be provided by Enbridge in connection with any Subcontract, the Consultant shall not be relieved of any of its liabilities and responsibilities hereunder. Any party which enters into a Subcontract with the Consultant shall be required by the terms of such Subcontract to comply with and be bound by the obligations and responsibilities of the Consultant described hereunder and without restricting the generality of the foregoing, any Subcontract which has been entered into without the prior written consent of Enbridge shall be null and void and without force and effect.

13. **Insurance**

Save and except where Enbridge specifies otherwise in writing, the Consultant shall at its own expense maintain and keep in full force and effect during the Term hereof and for a period of two (2) years following the expiry of the Term or other termination of this Agreement:

(a) Commercial General Liability insurance having a minimum inclusive coverage limit, including personal injury and property damage, of at least Two Million Dollars ($2,000,000) per occurrence. Enbridge Gas Inc. must be listed as the certificate holder and be added as an additional insured in the insurance policy, which should be extended to cover contractual liability, products/completed operations liability, owners'/ contractors' protective liability and must also contain a cross liability clause;

(b) Automobile Liability insurance on all vehicles used in connection with this Agreement and such insurance shall have a limit of at least Two Million Dollars ($2,000,000) in respect of bodily injury (including passenger hazard) and property damage inclusive of any one accident;

(c) Non-Owned Automobile Liability insurance and such insurance shall have a limit of at least Two Million Dollars ($2,000,000) in respect of bodily injury (including passenger hazard) and property damage, inclusive in any one accident; and

(d) such other insurance as Enbridge may in its discretion determine to be necessary, including, but not limited to, Professional Liability or Errors and Omissions insurance.

The Consultant shall forthwith after entering into this Agreement, and from time to time thereafter at the request of Enbridge, furnish to Enbridge a memorandum of insurance or an insurance certificate setting out the terms and conditions of each policy of insurance (all such policies of insurance being hereinafter described as the "Insurance Policies") maintained by the Consultant in order to satisfy the requirements of this section. At any time and from time to time at the request of Enbridge, the Consultant shall furnish Enbridge with one or more duly completed insurance certificates in the form requested by Enbridge to evidence the details of all the Insurance Policies. The Insurance Policies shall be arranged with insurers acceptable to Enbridge, acting reasonably, and shall contain such terms and conditions as are reasonably acceptable to Enbridge. The Consultant shall not cancel, terminate or materially alter the terms of any of the Insurance Policies without giving prior notice in writing to Enbridge. The Consultant shall cause or arrange for any of its insurers under any one or more of the Insurance Policies to oblige itself contractually in writing to Enbridge to provide fifteen (15) days prior notice in writing before cancelling, terminating or materially altering the Insurance Policies under which it is an insurer.

14. **Compliance with Laws**

The Consultant agrees to comply with the Occupational Health and Safety Act (Ontario) and the Workplace Safety and Insurance Act (Ontario) and with all other prevailing federal, provincial and municipal laws and regulations or any other laws or regulations in force in any jurisdiction where the Services are performed (the "Laws") and which are applicable to the Consultant, its subcontractors and the Services provided hereunder, and the Consultant shall familiarize itself and procure all required permits and licenses and pay all charges and fees necessary or incidental to the due and lawful prosecution of this Agreement, and maintain all documentation as may be required by the Laws, and shall indemnify and save harmless Enbridge, its directors, officers, agents and employees thereof against any claim or liability from or based on the violation of any Laws, whether by the Consultant, its officers, employees, subcontractors, representatives or agents. The Consultant shall, from time to time, if requested by Enbridge, furnish Enbridge with evidence of such compliance, and in particular: (i) evidence from the Workplace Safety and Insurance Board, or the equivalent thereof in any jurisdiction where the Services provided hereunder are carried out, that the Consultant and any party with which it has entered into a Subcontract are in compliance with and have paid all assessments and other amounts owing pursuant to the workers' compensation legislation of such jurisdiction; and (ii) evidence of the Consultant's compliance with any training requirements under the Laws including, without limitation, the provision of such statements or certificates pertaining to the Consultant's compliance in the form(s) prescribed by Enbridge from time to time.

Enbridge is committed to compliance with the Accessibility for Ontarians with Disabilities Act, 2005, O.Reg. 429/07 and O.Reg. 191/11, the Enbridge Customer Service Policy for Providing Goods and Services to People with Disabilities and the Enbridge Integrated Accessibility Standards Policy (collectively the "AODA"). The Consultant shall ensure that it is in full compliance with all of its obligations under AODA. Without limiting the generality of the foregoing the Consultant shall ensure that all of its employees, agents, volunteers, or others engaged by the Consultant in the delivery of services under this Agreement receive training in connection with the requirements of the AODA. If requested to do so, the Consultant shall provide Enbridge with copies of its policies, practices, procedures, training materials and training records including the dates on when the training is provided, and the names of the individuals trained, and confirmation the Consultant has reported its compliance to the Ministry of Community and Social Services or such other governmental authority as provided in the AODA.

The Consultant will ensure that any personnel it assigns to work in Canada, where they are not a Canadian citizen or Canadian permanent resident of Canada, will obtain and maintain the lawful ability to engage in commercial activities in Canada through the issuance of the appropriate documentation from Canada Border Services Agency and Citizenship and Immigration Canada. The Consultant's personnel where necessary will obtain lawful work permits to engage in business-related activities as temporary foreign workers and will notify Enbridge if any applications for work permits and work permit renewals are refused. The Consultant will not send personnel to any Enbridge-related work site if they do not possess the necessary lawful permission to work in Canada. The Consultant will take full responsibility to secure the necessary documentation and produce such documentation when entering a Canadian work site of Enbridge.

15. **Waiver**

Either the Consultant or Enbridge may, in writing, extend the time for performance by the other and waive non-compliance or non-performance by the other of any of the other's obligations, covenants and agreements under this Agreement and any compliance therewith or performance thereof. However, no such extension or waiver shall operate so as to waive, diminish or reduce the scope of or otherwise affect any obligation, covenant or agreement of such other which is not the subject matter of such extension or waiver or, except to the extent of such extension or waiver, of the obligation, covenant and agreement which is the subject matter of such waiver. No act or failure to act of either the Consultant or Enbridge shall be or be deemed to be an extension or waiver of timely or strict performance by the other of the other's obligations, covenants and agreements under this Agreement except to the extent notice thereof is given to the other.

16. **Notice**

Any notice or other communication to be given under or pursuant to the provisions hereof or in any way concerning this Agreement shall be sufficiently given if reduced to writing and delivered to the person to whom such communication is to be given or sent by facsimile or electronic internet communication, addressed to such person at the address set forth below:

If to Enbridge:

ENBRIDGE GAS INC.

50 Keil Drive North, Box 2001
Chatham ON N7M 5M1
Attention: Sophear Net, Specialist BD
Phone: 519-436-4600 ext. 5002394
Email: sophear.net@enbridge.com

With a copy to: Law Department
Facsimile: 416-495-5994

If to the Consultant:

POSTERITY GROUP CONSULTING INC.
43 Eccles Street, Unit 2 – Second Floor
Ottawa Ontario K1R 6S3
Attention: Alex Tiessen, Principal
Phone: (613) 219-5312 Ext.
Email: tiessen@posteritygroup.ca

or at such other address as may be specified therefor by proper notice hereunder. A notice or communication shall be deemed to have been sent and received on the day it is delivered personally or by courier or by facsimile or by electronic internet communication. If such day is not a business day or if the notice or communication is received after 5:00 PM (at the place of receipt) on any business day, the notice or communication shall be deemed to have been sent and received on the immediately following business day.

17. **Interpretation**

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. Headings used herein are for the convenience of reference only and shall not be considered in construing or interpreting this Agreement. The words "herein", "hereunder", "hereof" and other similar words refer to this Agreement as a whole and not to any particular paragraph. Any provision herein prohibited by law shall to the extent prohibited be ineffective without invalidating any other provisions hereof. All references to amounts of money in this Agreement and any schedule shall mean lawful currency of Canada.

18. **Assignment**

The Consultant may not assign this Agreement in whole or in part without the express prior consent in writing of Enbridge. This Agreement shall be binding upon and enure to the benefit of the successors and assigns of Enbridge.

19. **Use of Enbridge Name and Logo**

The Consultant shall not use or display Enbridge's name or any symbols, signs, trademarks and other marks denoting and identifying Enbridge in any manner whatsoever without the prior written authorization of Enbridge.

20. **Time of Essence**

Time shall be of the essence in the performance of the Services.

[remainder of page intentionally left blank]

21. **Survival**

All warranties and indemnities contained in this Agreement, and the obligations contained in Section 8, shall survive the termination of this Agreement irrespective of the time of or party responsible for such termination, and such warranties, indemnities and obligations shall remain in full force and effect and be binding on the Contractor notwithstanding such termination.

22. **Further Assurances**

Each of the parties shall, from the time of the written request of the other party, do all such further acts and execute and deliver or cause to be done, executed or delivered all such further acts, deeds, documents, assurances and things as may be required, acting reasonably, in order to fully perform and to more effectively implement and carry out the terms of this Agreement.

23. **Entire Agreement**

This Agreement, including any schedules attached hereto, constitutes the entire agreement between the parties with respect to the subject matter set out herein and replaces any prior understandings or agreements, whether written or oral, regarding such subject matter. No change or modification of this Agreement is valid unless it is in writing and signed by both parties. No disclaimers, purchase order documents, invoices or other documents of the Consultant shall be binding upon Enbridge.

24. **Audit**

The Consultant shall, following no less than seven (7) business days advance notice in writing, provide to such auditors (including external auditors and Enbridge's internal audit staff or agents) as Enbridge may designate in writing, supervised access to the data, records and supporting documentation maintained by the Consultant with respect to the Services solely for the purpose of: (i) performing audits and inspections to enable Enbridge to satisfy applicable regulatory requirements or certify compliance with applicable laws; and (ii) to confirm that the Services are being provided in accordance with the terms of this Agreement. Enbridge and its auditors shall use commercially reasonable efforts to conduct such audits in a manner that will result in a minimum of inconvenience and disruption to the Consultant's business operations. In the event that if any such audit reveals any: (a) errors or deficiencies in the completion of the Services or invoicing of the Services; or (b) overpayments to the Consultant by Enbridge, then the Consultant shall forthwith correct such errors or deficiencies, including if applicable refunding any overpayment to Enbridge. The Consultant shall retain all records for ten (10) years from the date of expiration or earlier termination of this Agreement, or such longer period as Enbridge may require having regard to the nature of the Services.

25. **Enbridge Policies**

The Consultant acknowledges receipt of a copy of each of Enbridge Inc.'s Statement on Business Conduct for Enbridge Inc. and its Subsidiaries and Lifesaving Rules, each as amended from time to time (the "Policies"). The Consultant agrees to comply with the Policies in connection with its delivery of the Services described in this Agreement, and agrees that, if requested by Enbridge, it will ensure all personnel delivering the Services herein attend training on the Lifesaving Rules.

26. **ISNetworld Requirement**

If required by Enbridge, the Consultant shall subscribe with ISN Software Corporation as a registrant of ISNetworld ("ISN") or any successor service mandated by Enbridge from time to time, and maintain a performance grading within ISN that is acceptable to Enbridge (the "ISNetworld Requirement") and shall: (a) provide all records and information as required by ISN or Enbridge, including, but not limited to, training and qualification data of the Consultant personnel, including subcontractors and employees, relating to the Services; and (b) maintain compliance with the ISNetworld Requirement during the currency of this Agreement.

[remainder of page intentionally left blank]

27. **Counterparts and Execution**

This Agreement may be executed by the parties in separate counterparts, each of which when so executed and delivered will be deemed to be an original, and all such counterparts will together constitute one and the same instrument. Delivery of a signature by electronic transmission or by facsimile transmission, including by email delivery of a "portable document format" ("pdf") document, shall create a valid and binding obligation. This Agreement may be executed using electronic signatures.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first written above.

POSTERITY GROUP CONSULTING INC.	**ENBRIDGE GAS INC.**
Digitally signed by Alex Tiessen DN: cn=Alex Tiessen, o=Posterity Group Consulting Inc., ou, email=tiessen@posteritygroup.ca, c=CA Date: 2020.07.21 17:36:43 -04'00'	Fiona Oliver Glasford (Jul 23, 2020 09:09 EDT)
By: ______	By: ______
Name: Alex Tiessen	Name: Fiona Oliver-Glasford
Title: Principal	Title: Manager Carbon Strategy
By: ______	By: ______
Name:	Name: * *
Title:	Title: *
(Please print name and title of Signing Officer)	

Witness: ______

Name:

(Witness required if Contractor is a Sole Proprietor)

SCHEDULE A

TO THE CONSULTING AGREEMENT BETWEEN ENBRIDGE GAS INC. AND POSTERITY GROUP CONSULTING INC. Dated July 20, 2020

This Schedule is made under the above referenced consulting agreement (the "Agreement") between ENBRIDGE GAS INC. ("Enbridge") and POSTERITY GROUP CONSULTING INC. (the "Consultant").

1. **SCOPE OF SERVICES**

The Consultant will undertake the following Services:

Support the Energy Transition Scenario Analysis ("ETSA") by modeling future load at the granular level of energy end uses, different building types, rate classes, and regions, and undertaking scenario analysis to explore several possible economic and policy scenarios under which Enbridge may operate in the future.

A description of Services and key personnel to be provided by the Consultant is set forth in the proposal dated July 15, 2020 prepared by the Consultant, which is attached as Attachment 1 to this Schedule (the "Proposal") and incorporated by reference herein. In the event of a conflict between the terms and conditions set out in the Proposal and those set out in this Agreement, the terms and conditions in this Agreement (including this Schedule) will govern and take precedence.

2. **DELIVERABLES**

The Consultant will provide the following deliverables:

Complete activities under four work packages:

Work Package 1: Characterize Critical Drivers and Finish Developing Reference Case

Work Package 2: Parametric Analysis and Boundary Scenario Definitions

Work Package 3: Planning Scenario Definitions

Work Package 4: Scenario Analysis and Modelling

As detailed further in the attached proposal.

3. **TERM AND COMMENCEMENT AND COMPLETION DATES**

This Schedule shall be effective as of July 20, 2020 and expire March 1, 2021, or such other date as the parties may mutually agree in writing.

4. **KEY PERSONNEL**

The Consultant will provide the following personnel to deliver the services set out above under Scope of Services:

Alex Tiessen, Principal

5. **FEES AND PAYMENT TERMS**

Fees: [redacted]

Expenses: N/A

The above fees and expenses cannot be exceeded without prior written approval from Enbridge.

Fees are payable by Enbridge within forty-five (45) days of receipt from the Consultant of an appropriate invoice setting out in reasonable detail the nature of the services provided.

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Dated as of July 20, 2020.

POSTERITY GROUP CONSULTING INC.	**ENBRIDGE GAS INC.**
By: Digitally signed by Alex Tiessen DN: cn=Alex Tiessen, o=Posterity Group Consulting Inc., ou, email=tiessen@posteritygroup.ca, c=CA Date: 2020.07.21 17:37:19 -04'00'	By: Fiona Oliver Glasford (Jul 23, 2020 09:09 EDT)
Name: Alex Tiessen	Name: Fiona Oliver-Glasford
Title: Principal	Title: Manager Carbon Strategy
By:	By:
Name:	Name: * *
Title:	Title: *
(Please print name and title of Signing Officer)	

Witness:

Name:

(Witness required if Contractor is a Sole Proprietor)

ATTACHMENT 1, Proposal is attached at the following pages.

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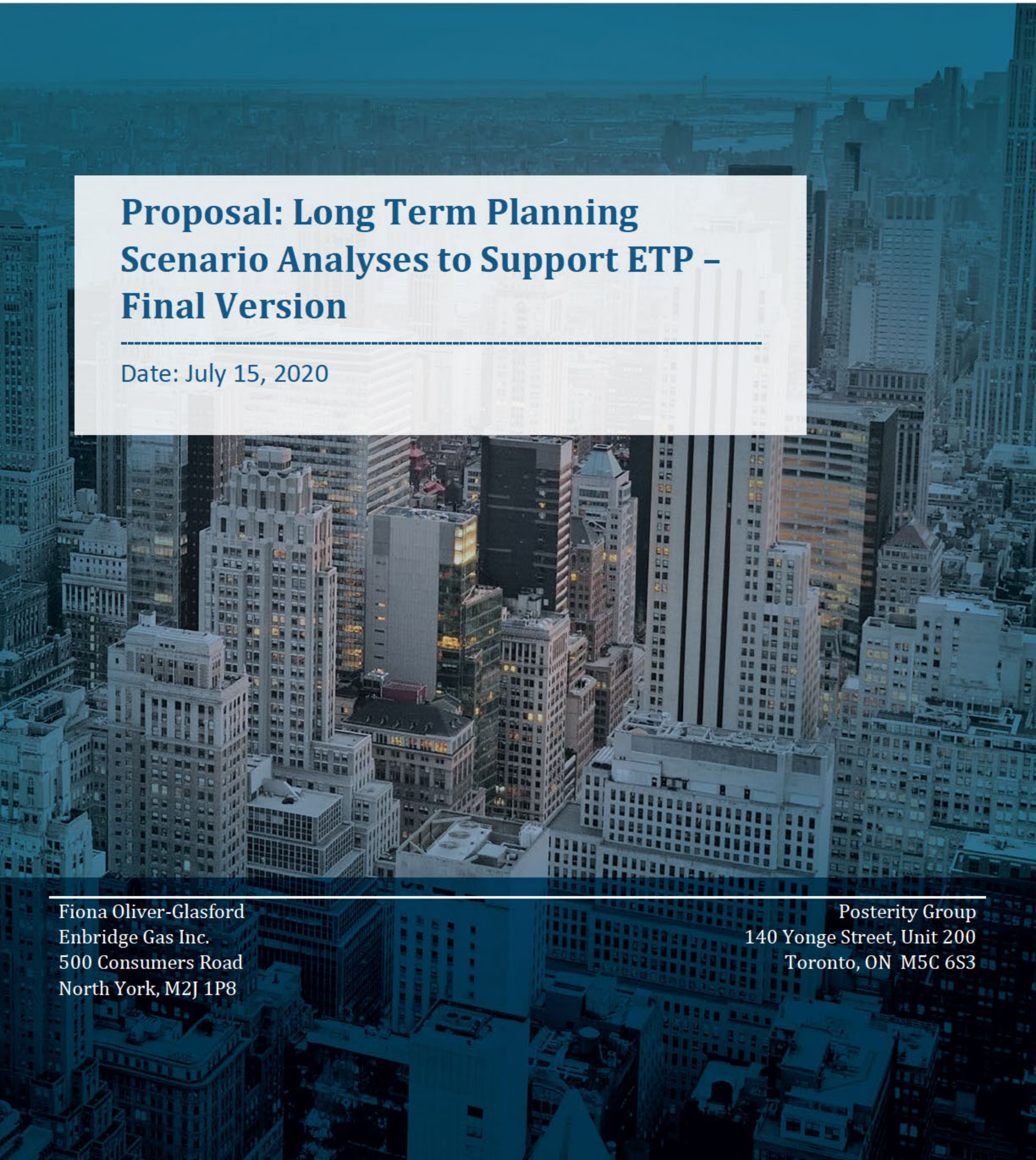

Proposal: Long Term Planning Scenario Analyses to Support ETP – Final Version

Date: July 15, 2020

Fiona Oliver-Glasford
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Toronto, ON M5C 6S3

Contents

1 Introduction

Posterity Group Consulting Inc. (Posterity Group) is pleased to submit this draft proposal to Enbridge Gas Inc. (Enbridge). We understand senior staff at Enbridge need to consider the financial and operational impacts of the range of climate policy related impacts Enbridge could face over the next 30 years. Enbridge's Energy Transition Planning (ETP) project team is working across departments (Load Forecasting, Network planning/system planning, Asset Management, Gas Supply, Rate and Regulations) to facilitate discussions, collect information, and provide senior decision makers with a quantified range of potential planning scenarios.

This document outlines how Posterity Group will support the Energy Transition Scenario Analysis (ETSA) by modeling future load at the granular level of energy end uses, different building types, rate classes, and regions, and undertaking scenario analysis to explore several possible economic and policy scenarios under which Enbridge may operate in the future.

We propose a methodology which has successfully been used with FortisBC to undertake scenario analyses in support of its Long-Term Gas Resource Plan (LTGRP) filings to the BCUC. Posterity Group successfully supported FortisBC using this methodology for its 2017 LTGRP filing and is currently engaged in support of their 2022 LTGRP submission.

In this engagement, Enbridge will be able leverage internal modelling, forecasting and research the company is already undertaking (e.g., Enbridge's load forecast, Enbridge's hydraulic model 'Synergi Gas'). Enbridge will also be able to build on previous investments in its:

- Jurisdictional end-use level dataset developed in support of ongoing DSM planning and IRP analysis, and the
- Power BI user-interface tool currently being developed to support energy efficiency planning for both DSM and IRP.

The approach presented in the following section will involve:

- Defining critical drivers, characterizing their relational effects, and establishing possible ranges and likely probability distribution of these ranges;
- Building out a more comprehensive end-use level reference case, including adding electric end-uses and gas rate classes;
- Undertaking parametric analysis to understand the effects of each critical driver over its range in the forecast period;
- Undertaking analysis to bound the possible futures, i.e., defining upper and lower boundaries to establish a cone of uncertainty;
- Using visualization via the Power BI user-interface tool to facilitate development of 'what if' planning scenario narratives; and
- Assessing directional change of critical drivers for each planning scenario, quantifying impacts to critical drivers, and undertaking scenario modelling.

At the end of this engagement Enbridge will have a comprehensive end-use level dataset that reflects several possible futures and a user-interface tool that allows decision makers to explore this dataset and distill quantitative impacts (e.g., how gas use and GHG emissions will change) under different forecast scenarios.

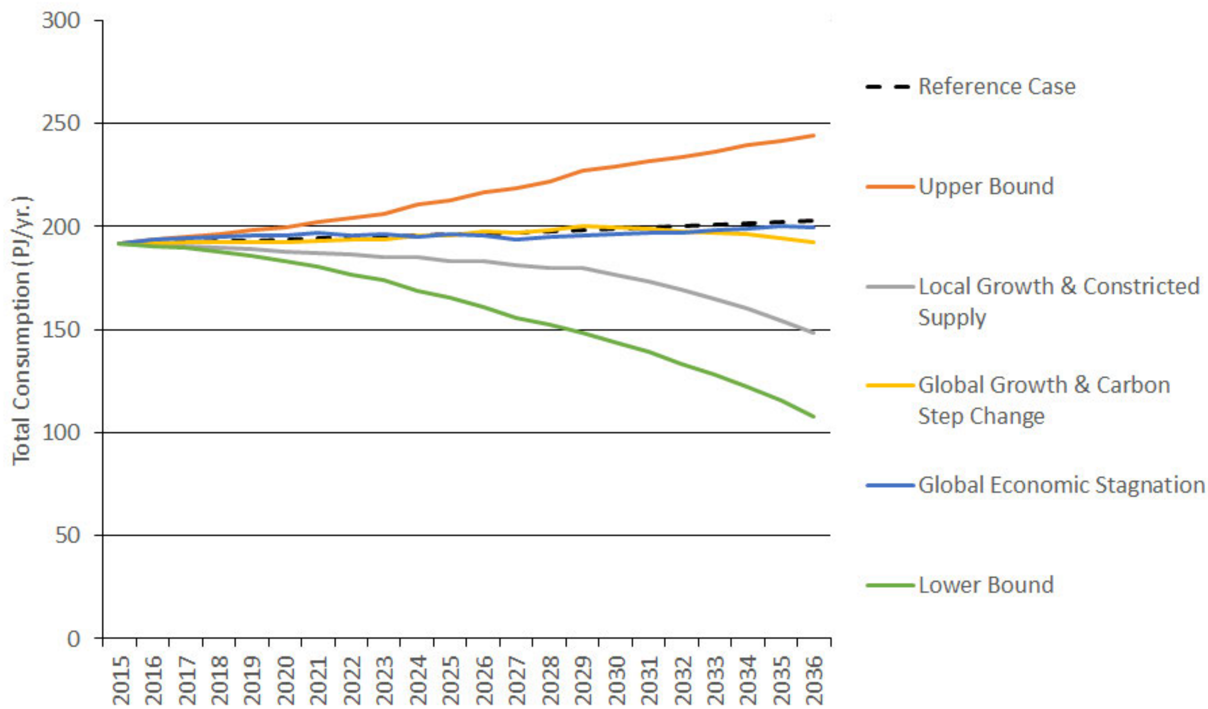
2 Approach

Our proposed approach involves defining the range of possible future operating environments from two perspectives:

1) An 'if, then' bottom up method that identifies critical drivers which could have a meaningful influence on gas use in Ontario (e.g., carbon price), defines the relational effects between each driver and how gas use is influenced (e.g., carbon price will influence fuel switching via price elasticity at the customer level), and the possible range (e.g., $50/tonne - $200/tonne). We can then examine the impacts of these drivers varying over their possible ranges and use this analysis to define an upper and lower bound. *[Work Packages 1 and 2]*

2) A 'what if' scenario development method that leverages the 'if, then' analysis to explore and define plausible future narratives (e.g., 80% GHG reduction by 2050) and quantifies what critical drivers look like under these scenarios; allowing each scenario to be modelled at an end-use level. *[Work Packages 3 and 4]*

Exhibit 1 – Example Output after Completing Both 'If, Then' and 'What If' Methods



We recommend completing activities under four work packages:

- Work Package 1: Characterize Critical Drivers and Finish Developing Reference Case
- Work Package 2: Parametric Analysis and Boundary Scenario Definitions
- Work Package 3: Planning Scenario Definitions
- Work Package 4: Scenario Analysis and Modelling

Work Package 1 – Characterize Critical Drivers and Finish Developing Reference Case

Activity 1.1 – Initiation Meeting

***Objective**: Define key critical drivers; Solicit input and direction from Enbridge Energy Transition Scenario Analysis (ETSA) team*

***Deliverables**: Meeting minutes*

The initiation meeting will identify logistical, scheduling and communications issues and protocols and will be an opportunity for the consulting team to request specific data and research products.

The second part of the meeting will involve a working session which will focus on prioritizing critical drivers "CDs" and collecting input and context from the Enbridge ETSA team [See Appendix A for a list of potential CDs]. We will also identify relevant internal Enbridge stakeholders and define agenda items ahead of the discovery sessions described in Activity 1.2.

Activity 1.2 – Discovery Sessions

***Objective**: Meet with Enbridge staff to identify relevant internal data and research, discuss relational effects and solicit input on reasonable ranges (and likely probability distribution of these ranges) for each of the key critical drivers.*

***Deliverables**: Meeting minutes*

Under this activity, a series of discovery meetings (1-2 hours each) will be held with Enbridge staff across different departments to solicit input and identify relevant internal data sources (e.g., information on RNG, Hydrogen research and forecasts).These may include:

- Network Planning/IRP
- Load Forecast (and load forecast inputs),
- Gas Supply Planning
- Renewable Gases forecasting (staff familiar with RNG and Hydrogen),
- Carbon Capture & Storage,
- Transportation or other load growth
- Codes/Standards/Government Relations
- Carbon Pricing
- Revenue Requirements/Rate Impacts

**If Enbridge can do most of this work, PG effort can be scaled back, but not completely. At a minimum, effort needed to provide direction on what input is required and to review and process outputs (~ 16 hours).*

Activity 1.3 – Identify & Collect Additional Data Sources, Finalize Critical Driver Assumption Tables

***Objective**: Compile a complete characterization of key critical drivers, with details on relational effects, possible ranges, and the likely probability distribution of these ranges (e.g., are they normally distributed?).*

***Deliverables**: Critical Driver Assumption Tables*

We will work with the Enbridge ETSA team to follow up and collect information discussed during the discovery sessions. If forecasts for certain drivers do not exist (e.g., RNG potential and cost points), Posterity Group can help advise on reasonable ranges.

We will also work with Enbridge to facilitate access to relevant external data sources. For example:

- Permission to use data from Posterity Group's 2017 MOECC study; and
- Permission to use IESO APS data, so that end-use fuel share components can be built out and be aligned with APS.

Activity 1.4 – Finish Developing Reference Case

Objective: *Build out a more comprehensive end-use level reference case, including adding electric end-uses and gas rate classes*

Deliverables: *More comprehensive reference case dataset (to be provided under Work Packages 2 and 4)*

During this activity we will build-out additional elements of the reference case in Enbridge's existing end-use model. For example, the current model does not include electricity or other fuel use (or gas fuel shares) so effort will be required to determine the scale of potential for switching from electricity (or other fuels) to/from gas.

We also plan to add gas rate classes at this point to enhance future functionality of the model (e.g., introducing rate classes will be important for assessing rate impacts of forecasted gas use changes).

Work Package 2 – Parametric Analysis and Boundary Scenario Definitions

Activity 2.1 – Parametric Analyses

Objective: *Understand the effects of each critical driver over its range in the forecast period*

Deliverable: *Inputs to Activity 2.2 deliverable*

A parametric analysis will be undertaken for each critical driver of interest to understand the effects of each critical driver over its range in the forecast period. This activity will include analysis against the reference case.

The output of this parametric analysis will be represented as a set of functions describing how volume and peak is affected by each critical driver over its range.

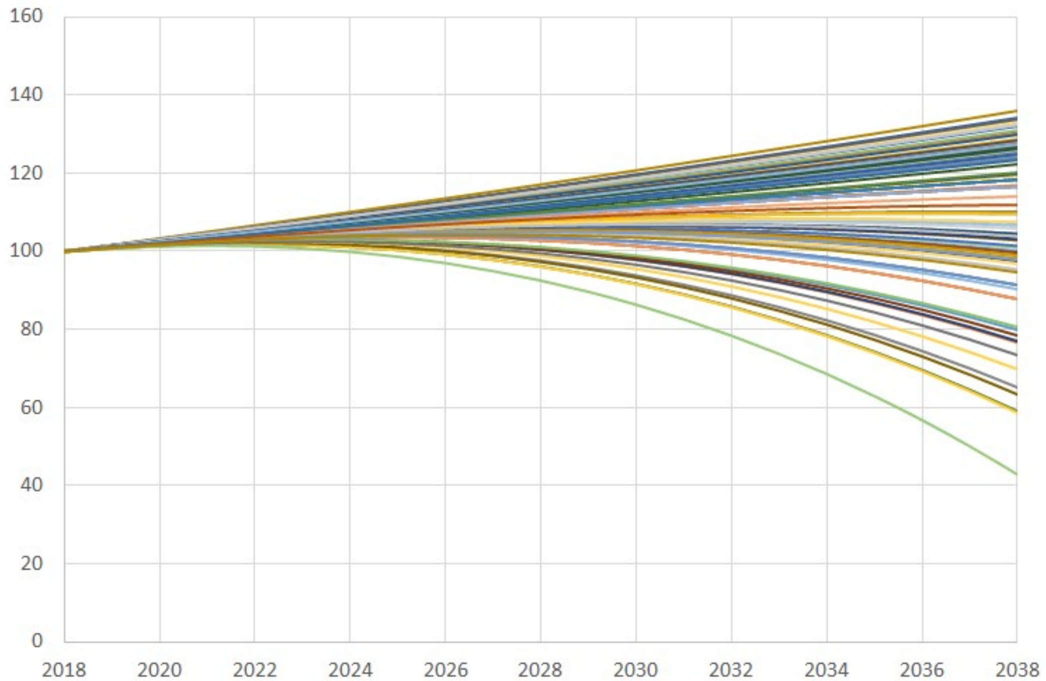
Activity 2.2 – Boundary Scenario Definitions

Objective: *Bound the possible futures, i.e., defining upper and lower boundaries to establish a cone of uncertainty.*

Deliverable: *Planning dataset (including reference case outputs, upper and lower boundary scenarios, and critical driver sensitivity outputs)*

Subject to discussion with Enbridge, this activity could involve conducting stochastic (i.e., probabilistic) simulation using the probability distributions assigned to the critical drivers. We plan to vary the 5 most impactful critical drivers, while holding all others constant. The outcome of this simulation will allow us to define upper and lower bounds to the forecast.

Exhibit 2 – Stochastic Simulation Example



Activity 2.3 – Update User-Interface Tool

***Objective**: Provide intuitive access to the planning dataset and present information in an actionable format*

***Deliverable**: Updated Power BI user-interface to support Work Package 3 planning session*

This activity involves updating the Power BI user-interface tool currently being developed to support DSM and IRP planning. This tool will allow Enbridge users to interact with the detailed modelled planning data set and quickly explore the impact of changing one or several critical drivers over a planning period. Users will be able to adjust 'sliders' to see the effects of varying different critical drivers and see how outcomes compare to the reference case, and where they are positioned relative to the upper and lower boundaries.

Work Package 3 – Planning Scenario Definitions

Activity 3.1 – Planning Session to Develop Scenario Narratives

***Objective**: Define planning scenario narratives*

***Deliverable**: Scenario narratives and instructions on directional change of critical drivers*

Under this activity, the consulting team will facilitate a workshop with Enbridge stakeholders to define a set of 'what if' planning scenarios; first via narrative, then in relation to the directional change in each of the critical drivers. This activity will have three parts:

<u>Part 1 - Pre-planning session preparation</u>

The objective of part one is to develop strawman planning scenario descriptions

Ahead of the planning session, we will solicit input from the Enbridge ETSA team and additional company stakeholders to draft strawman scenario descriptions. We have budgeted for 3 planning scenarios, which could potentially include:

- A consensus scenario that describes what Enbridge "thinks will happen",
- An aggressive decarbonization scenario (e.g., 80% GHG reduction by 2050), and
- A utility decentralization scenario with rapid technological disruption, lower electric prices, the advent of smart cities and clean tech.

We imagine some of the thinking that went into the MaRs scenario work may be useful inputs to consider when developing these scenarios along with many other key thinking and work products for recent filings, etc.

<u>Part 2 - Planning session</u>

The objective of Part 2 is to finalize planning scenario narratives.

The planning session will be aided by the strawman scenario descriptions and by the user-interface tool developed in Work Package 2.

We will structure the planning session to provide attendees an overview of the critical drivers and their impacts, introduce the reference case and upper and lower boundaries, and then table the 'what if' planning scenarios for discussion.

We will discuss critical drivers relative to each planning scenario and session stakeholders will be able to adjust critical drivers across their range to see the impacts on the planning forecast.

<u>Part 3 - Post-planning session investigation and input</u>

The objective of Part 3 is to collect input on directional change and magnitude of change for each critical driver under each planning scenario.

As a following up to the session, we will provide instructions for users to navigate the user-interface tool to explore each planning scenario narrative and record their input on critical driver changes. We hope to solicit input from planning session attendees, as well as additional key stakeholder at Enbridge who were not able to attend the session. The goal is to have input from a large enough group of Enbridge stakeholders to leverage the benefits of 'crowd forecasting' to establish consensus on the direction of change (and the magnitude of this change) for each critical driver for each planning scenario.

Activity 3.1a – External Stakeholders - Develop Scenario Narratives

***Objective**: OPTIONAL ACTIVITY - Define external stakeholder-driven scenario narratives*

Deliverable*: Scenario narratives and instructions on directional change of critical drivers*

Under this activity, the consulting team will facilitate a workshop with Enbridge's external stakeholders to define 'what if' planning scenarios that incorporate external stakeholder views and input. This process can provide value in two ways:

- A more robust analysis can be developed by drawing on external knowledge and expertise, and
- Enbridge is given the opportunity to discuss ETP issues constructively with external stakeholders in an informal forum rather than as part of a regulatory proceeding. In Posterity Group's experience, this approach has often led to fewer, and more focused intervenor requests in subsequent regulatory filings.

This activity will be structured similarly to Activity 3.1, step 2. We anticipate using much of the same material and process to deliver an external-facing workshop to define scenarios, first via narrative; then in relation to the directional change in each of the CDs.

For the purposes of this proposal, we assume outputs from this session will inform 'Part 3' of the internal process outlined above (i.e., external input will ultimately inform the three internal planning scenarios).

Activity 3.2 – Develop Input Assumptions for Planning Scenarios

Objective*: Define input assumptions for each planning scenario based on outputs of Activity 3.1*

Deliverable*: Scenario input assumption tables*

We will review and collate findings from Activity 3.1 and draft a set of input assumptions for each planning scenario. The draft assumption tables will be circulated to the Enbridge ETSA team for review and input before finalizing.

Work Package 4 – Scenario Analysis and Modelling

Activity 4.1 – Scenario Modelling

Objective*: Provide a comprehensive end-use level dataset that reflects several possible futures and a user-interface tool that allows decision makers to explore this dataset and distill quantitative impacts (e.g., how gas use and GHG emissions will change) under different forecast scenarios*

Deliverable*: Complete planning dataset (including reference case outputs, upper and lower boundary scenarios, critical driver sensitivity outputs, and planning scenarios); Updated Power BI user-interface*

We will undertake detailed modelling of the defined planning scenarios, each representing a potential "future world" under which Enbridge would deliver services. The parametric analyses outputs developed under Work Package 2 and the input assumption developed under Work Package 3 will be used as inputs to model analyses for each of the planning scenarios.

The user interface tool will be updated as part of this activity to enable exploration of the future planning scenarios.

Activity 4.2 – Review Scenario Results with Enbridge and Revise

Objective: *Assess the degree of variation of results, and ground truth modelled impacts*

Deliverable: *Revised planning dataset and User-interface*

This activity is proposed because we understand producing scenario results can sometimes necessitate iteration. During this step we will review modelled results with the Enbridge ETSA team with two objectives:

- To assess whether the degree of variation in the results is sufficient to explore the desired range of outcomes, and
- To 'ground truth' the modelled impacts with respect to required actions in the physical world (e.g., rate of efficient new construction).

This activity is included as an explicit step for review and iteration.

3 Schedule

We propose the following milestone schedule:

Exhibit 3 – Milestone Schedule

Work Package	Work Package Timelines	Activity Completion Dates
1 – Characterize Critical Drivers and Finish Developing Reference Case	Mid July – Early September	A1.1 Late Jul A1.2 Early Aug A1.3 Mid Aug A1.4 Early Sep
2 – Parametric Analysis and Boundary Scenario Definitions	Mid September – Late October	A2.1 Early Oct A2.2 Mid Oct A2.3 Late Oct
3 – Planning Scenario Definitions	Early November – Early December	A3.1 Late Nov A3.2 Early Dec
4 – Scenario Analysis and Modelling	Mid December – Early Feb	A4.1 Mid Jan A4.2 Early Feb

4 Budget and Level of Effort

Exhibit 4 presents an estimated level of effort for each project activity; actual time required could vary across activities and work packages.

Exhibit 5 includes notes on each budget line item and indicates which activities are optional and where there is additional flexibility in the budget estimate.

Similar to previous engagements with Enbridge, we propose undertaking work on an hourly basis against an overall budget ceiling, with a monthly billing cycle for fees incurred in the preceding month.

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Exhibit 5 – Budget Notes

Work Package	Activity	Flexibility Category	Notes
WP1	1.1 Initiation Meeting	Core	Required to define key critical drivers, and solicit input and direction
WP1	1.2 Discovery Sessions	**Flexible**	If Enbridge can do most of this work, PG effort can be scaled back, but not completely. At a minimum, approximately [redacted] needed to provide direction on what input is required and to review and process outputs.
WP1	1.3 Additional Data Sources, Finalize CD Tables	Core	Scales based on final list of CDs. Relationship is not linear – some CDs require more effort to characterize and model.
WP1	1.4 Finish Developing Reference Case	Core	Required to build out a more comprehensive end-use level reference case, including adding electric end-uses and gas rate classes.
WP1	1.3a, 1.4a Provide Documentation	Core	Required to document assumptions.
WP1	PM Allowance	Core	Scales based on total WP effort.
WP2	2.1 Parametric Analysis	Core	Scales based on final list of CDs. Relationship is not linear – some CDs require more effort to characterize and model.
WP2	2.2 Boundary Definitions	Core	Required to define upper and lower boundaries.
WP2	2.3 Update User-Interface Tool	Core	Required to update and customize User-Interface to support WP3.
WP2	PM Allowance	Core	Scales based on total WP effort.
WP3	3.1 Internal Planning Session	Core	Scales based on final list of CDs, and # of planning scenarios.
WP3	3.1a External Planning Session	**Optional**	External stakeholder input.

Work Package	Activity	Flexibility Category	Notes
WP3	3.2 Develop Input Assumptions	Core	Scales based on final list of CDs, and # of planning scenarios.
WP3	3.2a Incorporate External Input	**Optional**	External stakeholder input.
WP3	PM Allowance	Core	Scales based on total WP effort.
WP4	4.1 Scenario Modelling	Core	Scales based on final list of CDs, and # of planning scenarios.
WP4	4.2 Review Scenario Results w/ EGI & Revise	Core	Scales based on depth of review and # of iterations required to finalize analysis.
WP4	4.1a, 4.2a Provide Documentation	Core	Required to document assumptions.
WP4	PM Allowance	Core	Scales based on total WP effort.

Appendix A Possible Critical Drivers

Exhibit 5 identifies 16 possible critical drivers (CDs).

Exhibit 6 – Potential Critical Drivers for Analysis & Inclusion in Scenario Analyses

#	Critical Driver	Source	Comments	Mode of Operation
1	Carbon price	Range defined by Enbridge/PG	Potential for multiple discrete trajectories. Note that current model does not include electricity or other fuel use (or gas fuel shares) so significant effort would be required to determine the scale of potential for switching from electricity (or other fuels) to/from gas based on additional carbon price.	Price driver – fuel switching via elasticity at the customer level
2	Natural gas price	Range defined by Enbridge	Note that current model does not include electricity or other fuel use (or gas fuel shares) so significant effort would be required to determine the scale of potential for switching from electricity (or other fuels) to/from gas based on commodity price.	Price driver – fuel switching via elasticity at the customer level
3	Renewable Natural Gas supply	Enbridge, based on internal (and perhaps external) stakeholder input	Potential for multiple discrete trajectories	Fuel switching: defined level of displacement of natural gas at the system level, possibly policy-driven via clean fuel standards.
4	RNG cost	Enbridge, based on internal (and perhaps external) stakeholder input	Potential for multiple discrete trajectories	Exogenous – assume RNG cost based on external Enbridge forecasts.

#	Critical Driver	Source	Comments	Mode of Operation
5	Hydrogen supply	Enbridge, based on internal (and perhaps external) stakeholder input	Potential for multiple discrete trajectories	Fuel switching: defined level of displacement of natural gas at the system level, possibly policy-driven via clean fuel standards.
6	Hydrogen cost	Enbridge, based on internal (and perhaps external) stakeholder input	Potential for multiple discrete trajectories	Exogenous – assume H2 cost based on external Enbridge forecast.
7	Customer growth	Enbridge	Potential for regional variation at the municipal level. (May require ability to hold customer numbers constant after specific years in specific regions)	Account growth
8	Natural Gas Transportation demand	Enbridge, based on internal (and perhaps external) stakeholder input	Customer segment definition would be required.	Defined level of fuel switching (from traditional transportation fuels). Addition of natural gas load in specific regions
9	Fuel switching	Enbridge or Enbridge/PG, based on internal (and perhaps external) stakeholder input	Potential for multiple discrete trajectories. Note that current model does not include Electricity use, so some effort would be required to determine scale of potential for switching from Electricity to Gas.	Policy Driver – Defined level of fuel switching: displacement of natural gas in specific regions, with the ability to vary input by sector. Price driver – fuel switching via elasticity at the customer level
10	Climate change impacts	PG to provide HDD/CDD estimates over study period	Potential for multiple discrete trajectories.	Treat as an exogenous driver: Examine effect of alternate HDD regimes on key scenarios.

#	Critical Driver	Source	Comments	Mode of Operation
11	Carbon capture impacts	Enbridge or Enbridge/PG, based on internal (and perhaps external) stakeholder input	Multiple discrete trajectories	Fuel switching: defined level of displacement of natural gas by "carbon captured natural gas" at the system or equipment level
12	Carbon capture costs	Enbridge, based on internal (and perhaps external) stakeholder input	Multiple discrete trajectories	Price driver – fuel switching via elasticity at the customer level
13	Price elasticity	Reference long-run price elasticity values developed by Posterity	Investigate at effects within a price elasticity range.	Treat as an exogenous driver: Examine effect of moving elasticity over its range on key scenarios.
14	New construction codes	Enbridge internal expertise & PG input to translate government statements into model inputs	Model how code impacts annual demand and the potential for running DSM programs.	Develop as a DSM scenario, or as an alternate baseline.
15	Retrofit codes	Enbridge internal expertise & PG input to translate government statements into model inputs	Model how code impacts annual demand and the potential for running DSM programs.	Develop as a DSM scenario, or as an alternate baseline.
16	Appliance standards	Enbridge/ PG	Model how standard impacts annual demand and the potential for running DSM programs.	Develop as a DSM scenario, or as an alternate baseline.

POSTERITY GROUP

ETSA – Additional Hours Proposal

Project: Energy Transition Scenario Analysis (ETSA)
Re: Additional hours required to help assemble data and fill data gaps
Submitted to: Enbridge
Submitted by: Posterity Group
Date Submitted: 16 November 2020

1 Introduction & Background

Posterity Group (PG) and Enbridge (EGI) recently conducted Discovery Sessions for the ETSA project and are now preparing to undertake parametric analysis for each of the Critical Drivers (CDs). Although the EGI project team is working hard to collect and prepare data related to the CDs, we have realized we underestimated the amount of time and effort required to finalize the CD data. We apologize that the effort to assemble data was underestimated in the original proposal.

Value and outcomes for Enbridge

An investment of additional time now will:

- Allow the PG team to provide the support required at this important phase of the project to help establish internal frameworks for thinking about long term planning and processes to collect and aggregate data. This investment will be valuable to EGI in future planning cycles.
- Reduce the risk of data and important information being missed or incorrectly used, resulting in a better planning dataset and possibly less re-work required later.
- Ensure we do not run out of hours later in the project. We want to make sure budgeted hours for future tasks are available so that we can successfully complete the project.

Request for additional hours

We are requesting additional hours to allow our team to:

1) Support EGI in its internal process of collecting CD input data. Guided by our recent work with FortisBC (who is going through their 3rd end-use based long-term resource planning cycle), we underestimated the support EGI requires.
2) Undertake research to fill data gaps. We did not budget specific effort to undertake independent research to fill CD data gaps (e.g., long-term price elasticity literature review research). The effort to undertake this research is less than we have incurred for similar work with other clients thanks to the expertise we have already established.
3) Adapt CD data provided by EGI and facilitate iterative consultations with EGI to finalize. We did not account for differences in data and approaches between legacy UG and EGD. We also overlooked the extent to which we need to extrapolate, fill data gaps, and propose assumptions regarding potential upper and lower scenario planning bounds (in our work with FortisBC, they have typically undertaken this effort internally).

2 Additional Support Activities

We are requesting additional level of effort for three activities.

Activity 1.5.1 - Support EGI in its internal process of collecting CD input data

- Additional hours to support EGI in identifying what information is relevant to a CD and thinking through modelling impacts. This includes additional working meetings, phone calls, and email communication.
- Providing additional templates and guidance to facilitate data assembly

Outcome: An easier experience for EGI staff to assemble CD-related data.

Activity 1.5.2 - Undertake research to fill data gaps

- There are gaps in data that EGI would like to address through additional research. For example, we have already identified EGI's short-term price elasticity assumptions are not applicable to the long-term planning exercise and there is a need for our team to propose long-term price elasticity assumptions based on a literature review. We anticipate there may be similar additional requirements to fill data gaps once the initial data from Enbridge has been assembled.

Outcome: The project has all the necessary input data to inform parametric analysis and scenario development activities; reduced burden on EGI staff to provide data.

Activity 1.5.3 - Adapt CD data provided by EGI and facilitate iterative consultations with EGI to finalize

- Extrapolate, consolidate, and adapt data
- Propose assumptions regarding potential upper and lower scenario planning bounds
- Consult with EGI to ensure any augmentations to the data (e.g., extrapolating or consolidating) are reasonable, and iterate if necessary

Outcome: CD data is structured properly to support parametric analysis and scenario development, minimizing the risk of data being misinterpreted or improperly treated in the modelling tasks; consensus on data augmentation.

3 Estimated Level of Effort

The table below presents a level of effort estimate for this work, but actual time required could vary for each activity. We recommend EGI consider approving a slightly higher budget ceiling; this would allow for greater flexibility in a situation where we (PG and EGI) jointly decide that more hours are required.

Activity	Activity Name	[redacted]		[redacted]
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ETSA – Reference Case Calibration Proposal

Project: Energy Transition Scenario Analysis (ETSA)
Re: Additional effort required to calibrate reference case to updated data
Submitted to: Sophear Net, Enbridge
Submitted by: Posterity Group
Date Submitted: 20 November 2020

1 Introduction & Background

The reference case being used for the ETSA project is based on the one developed for the recently completed APS (but includes some modifications made through our work supporting DSM planning and IRP activities). We understand Enbridge (EGI) has more recent base year and forecast data available. If EGI wants the ETSA project to reflect this updated information we could calibrate the APS reference case to align with EGI's recent data more closely; however, effort for this has not been scoped.

We would need direction very shortly if EGI wanted to make this update to avoid costly re-work (the reference case ideally needs to be updated before we can finalize parametric analysis and start scenario development activities).

Value for Enbridge

We understand EGI has an updated forecast that is using 2019 as the base year and includes an updated 10-year reference case trajectory.

Aligning the ETSA reference case with this updated information will allow ETSA scenarios to be compared to the most recent complete year of data and forecast. This means that changes to critical drivers will be more intuitive to EGI team members because alternate scenarios will be anchored around current base year data and an updated forecast trajectory.

It also improves the credibility of the outputs. For example, using the APS reference case assumptions entails a certain degree of risk; not all APS reference case assumptions make sense anymore, and some base year assumptions are unclear and difficult to trace.

Considerations for Enbridge

If moving to a 2019 base year and updated forecast trajectory, EGI needs to consider a couple elements:

- The ETSA project will be using base year and reference case numbers that differ from the DSM planning group (which is using the APS reference case); EGI needs to decide internally whether this is something that is acceptable.
- Whether EGI still wants to maintain a fully granular APS reference case for the ETSA project (2017 Base Year and forecast, with rate class and account information).

2 Proposed approach

We do not recommend undertaking a full, comprehensive update to the reference case; this is an extensive undertaking which we do not think is a good investment for EGI right now. Instead, a full update to the reference case should ideally be timed to support the next ETSA and APS planning cycles.

The simplified approach we recommend involves:

- Calibrating the APS 2019 consumption numbers so that they align with 2019 normalized actuals; essentially a step function change in the model, moving from a 2017 to a 2019 base year.
- Updating the APS reference case growth assumptions (2020-2038) to align with the EGI's updated 10-year forecast. In other words, adjusting the trajectory of the reference case to match EGI's current outlook.

What APS assumptions and structure would need to be maintained?

- Assumption about end use share. I.e., the % of gas that goes to each end use within each segment (except for industrial and large volume HVAC assumptions, which we are fixing).
- Sector segmentation structure. For example, to avoid significant additional effort, we need to maintain APS segment categories so that APS analysis outputs are still applicable.
- Similarly, assumptions about equipment/measure saturation will not be adjusted (nothing beyond what we have already adjusted for DSM planning purposes).
- Electricity end-use assumptions.

What are the impacts to the CD parametric analysis?

- We will need a full list of assumption that went into the updated 10-year forecast so that it is clear what CD assumption have changed between 2018 and 2020.
- This will be important because CD parametric analysis will be modelling the delta between a future CD assumption and the assumption embedded in the reference case.

3 Reference Case Calibration Activities

To calibrate the reference case to 2019 data, we would undertake two activities.

Activity 1.6.1 – Calibrate to 2019 actual data

- Calibrate 2019 APS data using 2019 normalized actuals for each sector, by segment and by rate zone
- Discuss data inconsistencies with EGI, if required, and iterate calibration.

Outcome: ETSA scenarios can be compared to the most recent complete year of data; More credible outputs.

Activity 1.6.2 – Update reference case growth assumptions

- Update the APS reference case growth assumptions (2020-2038) to align with the EGI's updated 10-year forecast. This includes updating the account growth and consumption growth for each sector, by segment and rate zone and extrapolating trend out to 2038.
- Discuss data inconsistencies with EGI, if required, and iterate calibration.
- We will require from EGI a full list of assumptions embedded in 10-year forecast, including but not limited to assumptions on codes and standards, gas price, carbon price, price driven fuel switching, and DSM.
- We will also need to understand if growth assumption should flatline (rather than continuing on the same trajectory) beyond the 10 year forecast for any of the segments-rate zone combinations.

Outcome: More intuitive critical drive modelling outputs because alternate scenarios will be anchored around current base year data and an updated forecast trajectory; More credible outputs.

4 Estimated Level of Effort & Schedule Impact

The table below presents a level of effort estimate for this work, but actual time required could vary for each activity.

Activity	Activity Name	[redacted]	[redacted]
		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]

The project schedule would be impacted by approximately 2-3 weeks. We would need to complete this work prior to finalizing parametric analysis and undertaking scenario analysis.

Energy Transition Scenario Analysis project Workplan & Schedule Revision

Project: Energy Transition Scenario Analysis
Re: Request to end the project by May 31, 2021
Submitted to: Jennifer Murphy and Cora Carriveau, Enbridge
Date Submitted: Revised 19 February 2021

1 Introduction & Background

We understand EGI would like to complete the project early because the current project completion date of June 30 is out of sync with internal needs. We believe we can complete the project a month earlier (May 31) by making workplan adjustments and revising the project budget.

Value for Enbridge

Finalizing the project sooner will allow EGI to incorporate project outputs in their internal planning processes. It should also reduce the risk of additional budget overruns.

Areas of Opportunity

We reviewed each active and upcoming project work package for opportunities to accelerate the project schedule without compromising the deliverables. We identified five areas of opportunity:

1) ETSA team (PG, EGI) to commit to timelines for providing feedback and information **[Additional Budget Required? No]**
   - Moving forward, we should be screening issues, questions, and items flagged for input to assess whether they have a material impact on the project outcomes, including whether input/feedback is on the critical path. Priority issues require deadlines for feedback and turn-around.
2) Support to address unbudgeted effort **[Additional Budget Required? Ideally]**
   - The project is currently tracking over budget, largely due to additional time required in work package (WP) #1 for the initiation meetings, discovery sessions, and defining and developing critical driver (CD) inputs.
   - This unbudgeted effort was important to help the EGI ETSA team build awareness about the scenario planning process and invest in its internal capacity to understand critical drivers and identify key input assumptions across the company

- In hindsight, we underestimated the time required to work with EGI to accomplish these activities largely because our budget estimate was guided by recent projects with FortisBC, who has already gone through several planning cycles
- The budget overrun is larger than we would like, but we acknowledge Posterity Group should share part of this risk
- We would like to request EGI consider adding budget to cover a portion of this overrun; any additional budget will be applied to the remaining project activities and will allow Posterity Group to complete the project with an improved budget outcome.

3) Remove external stakeholder activities from WP3 **[Additional Budget Required? No, budget reduction]**

- After discussion with Enbridge, we should decide whether external stakeholder tasks are required and if effort can be redeployed. Omitting activities 3.1a and 3.2a from the schedule will shorten the timeline for WP3 and reduce the risk of further schedule slip.
- Budget for these external stakeholder activities can be redeployed. The additional budget can support the scenario planning exercise, which we hope will ensure the subsequent tasks of scenario analysis and modelling can be conducted very efficiently.

4) Start WP3 now to complete WP3 sooner **[Additional Budget Required? Yes]**

- Initiate WP3 now so that we start working on the scenario narratives in parallel to WP2. We suggest having a draft of the scenario narratives and qualitative input assumptions in mid-March and finalize them using the results of WP2 in late March.
- We propose adding budget to cover additional effort in February and beginning of March. This effort will focus on facilitating a constructive planning session and streamlining post-planning input.

5) Reduce need for revisions in WP4 **[Additional Budget Required? No]**

- To meet a May 31 deadline, we are assuming revisions to the scenarios will be minimal, or perhaps not even required, due to time invested in the preceding work packages.

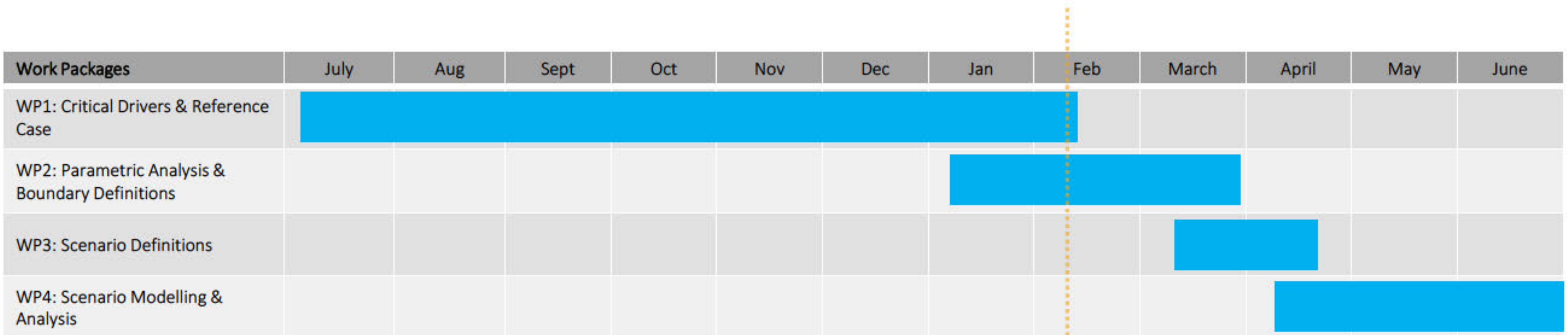
The following sections provide a summary of the current workplan, our proposed adjustments to accelerate the project timeline, and the estimated additional level of effort.

2 Current Workplan & Schedule

Figure 1 below provides a Gantt view of the schedule. This information is current as of February 12th, 2021 and shows that:

- The work packages (WP) are sequential, and currently have the following status:
  - WP1 is nearly complete
  - WP2 is underway
  - WP3 and WP4 have not started
- Project end date of June 30th, 2021

Figure 1 – Current Schedule, Gantt view



3 Revised Workplan & Schedule

We have reviewed each active and upcoming project work package for opportunities to accelerate the project schedule without compromising the deliverables:

All Work Packages

- Screen issues, questions, and items flagged for input to assess whether they have a material impact on the project outcomes, including whether input/feedback is on the critical path.
    - For priority issues, ETSA team to commit to timelines for providing feedback and information.
- Ensure sufficient budget is available to complete remaining activities.
    - WP1 is currently over budget, largely due to additional time required for the initiation meetings, discovery sessions, and defining and developing CD inputs.
    - We propose adding budget to ensure sufficient effort is available for the remaining project activities.

Work Package 2 – Parametric Analysis & Boundary Definitions

- We do not think it is feasible to accelerate WP2. The tasks in this work package are time intensive and are very difficult to accelerate without jeopardizing project outcomes.

Work Package 3 – Scenario Definitions

- We believe we can accelerate WP3 so that is starts mid-February and ends in late March:
    - Initiate WP3 now so that we start working on the scenario narratives in parallel to WP2. We suggest having a draft of the scenario narratives and qualitative input assumptions in early March and finalize them using the results of WP2 in late March.
        - We'd like to discuss how to we can update our approach for WP3. The objectives are:
            - Capitalize on the time window between mid-February and completion of WP2 to facilitate scenario narrative discussions and strategies with Enbridge *[Activity 3.1.1]*
            - Hold a constructive planning session as soon as WP2 is complete (i.e., as soon as the parametric analysis and slider tool are ready) *[Activity 3.1.2]*

        - Streamline post-planning session feedback and input to arrive at a final set of scenario definitions and qualitative input assumptions. *[Activity 3.1.3]*
    - After discussion with Enbridge, we should decide whether external stakeholder tasks are required and if effort can be redeployed. Omitting tasks 3.1a and 3.2a from the schedule will shorten the timeline for WP3 and reduce the risk of further schedule slip.
- Posterity Group to work with EGI to agree on a revised approach for WP3; the goal is to initiate work package activities as soon as possible, streamline stakeholder input, and minimize rework in WP4.

Work Package 4 – Scenario Analysis and Modelling

- We think we can slightly reduce length of WP4 so that the project can be completed by May 31st.
    - The main opportunity for reducing the timeline is in Activity 4.2 (reviewing and revising scenario modelling outputs). We expect the comprehensive feedback and input provided in the preceding work packages (WP1, WP2, and WP3) will ensure the scenario results are robust and will facilitate a shortened review and revision timeline.
    - We also propose redeploying effort from Activity 4.2 to Activity 4.1, to ensure draft results align with the intentions documented in WP3.
    - To meet a May 31 deadline, we are assuming revisions to the scenarios will be minimal, or not necessary.
- Rerunning the scenarios is time intensive and is difficult to accelerate due to the complexity of the model and size of the datasets. There is a minimum level of effort to make one adjustment because revisions to one aspect of a scenario typically have cascading effects in the model. If revisions are required, we will need to carefully discuss and agree on a complete list of revisions required prior to re-running the scenario models.

Revised Schedule

These suggested revisions result in the revised schedule presented in Figure 2 and Table 2 below.

Figure 2 – Revised Schedule, Gantt view

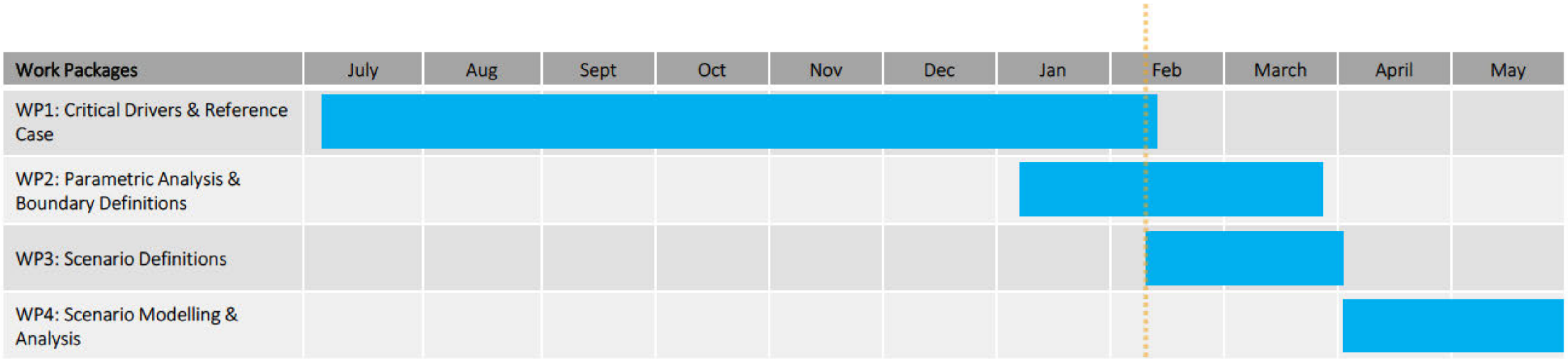


Table 1 – Revised Workplan

Task Name	Start	Finish	Status
WP1 - Critical Drivers & Reference Case	**07-20-20**	**01-12-21**	
WP1 PM	07-20-20	10-23-20	Complete
1.1 Initiation	08-25-20	08-25-20	Complete
1.2 Discovery Sessions	10-05-20	10-16-20	Complete
1.3 Additional Data Sources, Finalize CD Tables	08-31-20	10-09-20	Complete
1.4 Finish Developing Reference Case	09-28-20	12-04-20	Complete
1.4.1 Calibrate to 2019 actual data	12-07-20	01-04-21	Complete
1.4.2 Update reference case growth assumptions	12-14-20	01-11-21	Complete
1.5.1 - Support EGI in its internal process of collecting CD input data	10-19-20	12-31-20	Complete
1.5.2 - Undertake research to fill data gaps	10-19-20	12-31-20	Complete
1.5.3 - Adapt CD data and consult with EGI	10-26-20	12-31-20	In Progress
1.5.4 - Contingency	11-02-20	12-31-20	Complete
WP1 Documentation	12-23-20	01-12-21	Complete
WP 2 - Parametric Analysis & Boundary Definitions	**01-12-21**	**03-22-21**	
WP2 PM	01-19-21	03-22-21	In Progress

Task Name	Start	Finish	Status
2.1 Parametric Analysis	01-12-21	03-01-21	In Progress
2.2 Boundary Definitions	02-23-21	03-15-21	Not Started
2.3 Update User-Interface Tool	02-01-21	03-05-21	In Progress
WP2 Documentation	03-02-21	03-22-21	In Progress
WP 3 - Scenario Definitions	**02-16-21**	**03-26-21**	
WP3 PM	02-16-21	03-26-21	Not Started
3.1.1 Scenario Narrative Sessions Preparation	02-16-21	03-05-21	Not Started
3.1.2 Scenario Narrative Development Session	03-08-21	03-12-21	Not Started
3.1.3 Post-Session Information Consolidation	03-08-21	03-19-21	Not Started
3.2 Develop & Finalize Input Assumptions for Planning Scenarios	03-08-21	03-26-21	Not Started
WP3 Documentation	02-22-21	03-26-21	Not Started
WP 4 - Scenario Analysis and Modelling	**03-29-21**	**05-28-21**	
WP4 PM	03-29-21	05-28-21	Not Started
4.1 Scenario Modelling	03-29-21	05-14-21	Not Started
4.2 Review Scenario Results with Enbridge and Revise	05-17-21	05-28-21	Not Started
WP4 Documentation	05-03-21	05-28-21	Not Started

4 Estimated Additional Level of Effort & Budget

The table below presents a level of effort estimate and associated budget to complete the project on an accelerated schedule.

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
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POSTERITY GROUP

Level of Effort Estimate: Rebasing Support

Project: Energy Transition Scenario Analysis (ETSA)
Re: Estimated level of effort to facilitate using ETSA outputs for the rebasing application
Submitted to: Jennifer Murphy and Cora Carriveau, Enbridge
Submitted by: Alex Tiessen & Erika Aruja, Posterity Group
Version: 1
Date Submitted: 30 July 2021

The memo provides details on the additional effort and budget associated with supporting EGI with its rebasing application.

1 Scope of Work: Supporting EGI's Rebasing Application

As of July 15th, the ETSA project has gone over budget by 140 hours ($28,000):

- A component of this budget overrun is attributed to support Posterity provided to facilitate the use of ETSA scenario outputs by EGI's load forecasting group in their preparation for the upcoming rebasing application
- The project charter had not originally anticipated direct use of ETSA scenario outputs in EGI's rebasing application
- Additional effort was required to:
    - respond to inquiries,
    - participate in meetings,
    - enhance reporting outputs, and
    - revisit previous decisions made on critical drivers, scenario inputs, and base year and reference case calibration

2 Level of Effort & Budget: Supporting EGI's Rebasing Application

Exhibit 2 presents an estimate of the hours spent by the Posterity team between June 14 and July 15 in support of the rebasing application.

[redacted]

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POSTERITY GROUP

Scoping Document: Adjusting ETSA Scenarios

Project: Energy Transition Scenario Analysis (ETSA)
Re: Estimated level of effort to adjust the Diversified and Steady Progress scenarios
Submitted to: Jennifer Murphy and Cora Carriveau, Enbridge
Submitted by: Alex Tiessen & Erika Aruja, Posterity Group
Version: 2
Date Submitted: 30 July 2021

This memo provides an estimate of the level of effort, budget and schedule required to adjust the Steady Progress and Diversified Portfolio ETSA scenarios based on EGI's direction. We estimate [redacted] and an elapsed project schedule of 6 weeks.

1 Scope of Work: Scenario Adjustments

1.1 Adjustments Required

After reviewing outputs for the Steady Progress and Diversified Portfolio scenarios, EGI determined the scenario analysis should be revised to incorporate different input assumptions:

1. Apply the reference case account forecast to the Steady Progress and Diversified scenarios.

Scenario Title:	"Steady Progress"	"Diversified Portfolio"
ORIGINAL DRIVER ASSUMPTIONS *Customer Accounts (growth due to population/economic growth)*	Detached/Attached Residential: High (due to community expansion) Commercial and Multifamily Residential: High (due to community expansion) Industrial: Reference	Detached/Attached Residential: High (due to community expansion) Commercial and Multifamily Residential: High (due to community expansion) Industrial: Reference
ADJUSTED DRIVER ASSUMPTIONS *Customer Accounts (growth due to population/economic growth)*	Reference Case for all sectors.	Reference Case for all sectors.

2. Incorporate a customer defection assumption into non-price driven fuel switching for existing buildings in the Diversified scenario:

Scenario Title:	"Diversified Portfolio"
ORIGINAL DRIVER ASSUMPTIONS *Non-price driven fuel switching*	New Construction (**Res, Com sectors**) • Starting in 2030, 10% of new Res and Com buildings across the province won't connect to the gas grid because select communities ban gas; by 2038, 20% of new construction won't connect.

Scenario Title:	"Diversified Portfolio"
	Existing Buildings (**Res, Com sectors**) • Starting in 2026, province wide, 10% of gas-fired space & water heating equipment that is being replaced annually (due to equipment reaching end-of-life) will be replaced with electric equipment (due to incentives).
ADJUSTED DRIVER ASSUMPTIONS *Non-price driven fuel switching*	New Construction (**Res, Com sectors**) • Starting in 2030, 10% of new Res and Com buildings across the province won't connect to the gas grid because select communities ban gas; by 2038, 20% of new construction won't connect. Existing Buildings (**Res, Com sectors**) • Starting in 2026, province wide, 10% of gas-fired space & water heating equipment that is being replaced annually (due to equipment reaching end-of-life) will be replaced with electric equipment (due to incentives). • 10% of the customers installing new electric space heating equipment will disconnect from the gas system (the assumption is these customers only have 1 gas appliance)

1.2 Assumptions

- All remaining Critical Driver settings will be maintained.
- The output and results from these 'adjusted' scenarios will replace the 'original' output/results (i.e., these adjustments do not create new scenarios).

1.3 Activities Involved

As discussed, adjustments to critical drivers typically require cascading updates to other critical driver inputs and elements of the scenario analysis. For each scenario, we will need to:

- Adjust the model input assumptions for the 'customer accounts' driver [both scenarios] and 'non-price fuel switching' driver [Diversified Portfolio scenario only]
- Re-run the model:
  - Account growth modelling instructions will need to be updated [both scenarios]
  - Existing account modelling instructions will need to be updated [Diversified Portfolio scenario only]
  - Fuel share modelling instructions for existing accounts will need to be updated [Diversified Portfolio scenario only]
  - Target PJ/Blend % modelling instructions for RNG and Hydrogen will need to be recalibrated [both scenarios]
  - DSM savings potential modelling instructions will need re-solved and re-applied at the rate class level [both scenarios]
- Quality Control review the adjusted scenario outputs
- Update the study report and PowerBI dashboard
- Review with EGI and respond to questions
- Edit and submit final deliverables.

2 Schedule: Scenario Adjustments

The proposed schedule incorporates the following:

- Time to rerun the DSM budget solver model which takes several days of elapsed time.
- Time to incorporate final comments on the ETSA study report and PowerBI dashboard
- Summer vacation schedules (which may cause our team to take a bit longer to finish some activities).

Exhibit 1 – Proposed Schedule

Activity	Completion Timeline
Adjust model input assumptions	1 weeks after project initiation
Re-run the two scenarios	4 weeks after project initiation
QC output	5 weeks after project initiation
Update the study report and PowerBI dashboard	5 weeks after project initiation
Review with EGI and answer questions	6 weeks after project initiation
Submit final deliverables	6 weeks after project initiation

3 Level of Effort & Budget: Scenario Adjustments

Exhibit 2 presents a level of effort estimate and associated budget to complete the proposed scenario adjustments.

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Guidehouse

July 20, 2021

Heidi Steinberg Laxton
Project Manager
heidi.steinberglaxton@enbridge.com
Jennifer Murphy
Project Lead
jennifer.murphy@enbridge.com
Enbridge Gas Inc. (EGI)

Subject: Decarbonization Pathways Study

Dear Heidi & Jennifer,

With Enbridge Gas Inc. (EGI) currently preparing for a key rate rebasing period (2024-2028) and the continued policy narrative challenging the economy to address climate change, Ontario's integrated energy system is reaching a critical juncture. Energy systems are currently undergoing massive transformation in the ways that energy is generated, delivered, and consumed. The transformation is driven by a need to decarbonize systems and maintain resilient operations. Many advocacy groups and jurisdictional governments are promoting aggressive electrification of the energy system as an ideal solution to meet climate change targets. However, this position is largely unsupported by data on the feasibility and cost effectiveness.

Guidehouse is pleased to provide this proposal to EGI to provide a Decarbonization Pathways Study. We recognize that delivery of a decarbonized energy system requires a change to the commercial and regulatory structures governing the distribution sector. Policy and regulatory structure should provide a fair return for assets that serve the public's interest while supporting Canadian and Ontario government goals. These structures should also embrace mechanisms to mitigate risks associated with decarbonization. Specific and measurable guidelines are needed for utilities to demonstrate their assets complement the future energy system. This study will utilize our Low Carbon Pathways tools and analysis process to provide insights to inform internal planning efforts and educate external stakeholders, as necessary.

Our proposal highlights the extensive experience we have gained supporting the energy sector, including: utility companies, NGOs, and governments, with low carbon pathways analysis and GHG mitigation strategies. This proposal summarizes our tested approach that will support EGI with this very important work for the province of Ontario. The study will inform internal energy transition planning efforts related to, but not limited to, rebasing regulatory proceedings, scope 3 emission reduction targets, the Energy Transition Scenario Analysis (ETSA) project, and Integrated Resource Planning (IRP) work (i.e. the consideration of non-pipe solutions as alternatives instead of traditional infrastructure). The Study will also provide EGI with supporting material, including robust and defensible quantification of costs and benefits, to educate government, regulators and external stakeholders who are making energy transition decisions.

The key objectives of the project are to:

- **Develop** a robust comparative analysis of two decarbonization scenarios for the Ontario economy, including one focused on electrification-based mitigation strategies and one adopting a diversified, optimized low carbon fuels approach.
- **Analyse** the societal cost impacts of each decarbonization scenario.

- **Examine** the feasibility of decarbonization pathways and uncover a defendable and balanced policy narrative that supports provincial GHG reduction goals, manages costs for ratepayers and consumers and builds a narrative for EGI to communicate the role for clean fuels in a decarbonized future.

Guidehouse is uniquely positioned to support EGI with this assignment. The value of our approach includes:

1. **Extensive experience with the energy sector and climate change mitigation** strategy activities of Ontario and jurisdictions across North America, as well as expertise gained from our pioneering role in reframing the decarbonization narrative in Europe and British Columbia in the context of clean fuels.
2. **A tested database of GHG mitigation technologies and decarbonization initiatives**, inclusive of feasibility, potential, performance, and cost. For example, Guidehouse has led the DSM potentials examination for five provinces over the last several years and manages an industry-leading research practice tracking cost and performance data of electrification-focused clean tech and hydrogen production and storage technology
3. **Recent energy supply and demand modelling projects**, providing deep experience with provincial data and pre-established projections offering start up and level-setting efficiencies
4. **Deep understanding of the Ontario and Canadian climate policy experience**, the challenges, the opportunities, and lessons learned from narrowly focused, or siloed approaches to low carbon policy
5. **Access to core data, models, and cost information** to support a rigorous analysis at high value for money for EGI.

As a result of these capabilities and traits, our team is poised and excited to begin the next phase of Ontario's low carbon journey with you. We will deliver impactful and innovative thinking, tailored to the unique circumstances of the province and of EGI's customers.

Guidehouse is a leading global provider of consulting services to the public and commercial markets with broad capabilities in management, technology, and risk consulting. We help clients address their toughest challenges with a focus on markets and clients facing transformational change, technology-driven innovation and significant regulatory pressure. Across a range of advisory, consulting, outsourcing, and technology/analytics services, we help clients create scalable, innovative solutions that prepare them for future growth and success. Headquartered in Washington DC, the company has more than 10,000 professionals in more than 50 locations. Guidehouse is led by seasoned professionals with proven and diverse expertise in traditional and emerging technologies, markets and agenda-setting issues driving national and global economies. For more information, please visit: www.guidehouse.com.

Should you have any questions or concerns with this proposal, please contact me at 647.212.7187, or craig.sabine@guidehouse.com at your convenience.

Sincerely,

Craig Sabine,
Director, Energy Lead Canada

Guidehouse

Proposal for:

Decarbonization Pathways Study

ENBRIDGE

Submitted by:

Guidehouse Canada Ltd.
100 King Street West, Suite 4950
Toronto, ON M5X 1B1

416-956-5008
guidehouse.com

Reference No.: 219427
July 20, 2021

Table of Contents

Executive Summary

The Guidehouse team is ready and immediately available to support EGI with an examination of practical decarbonization pathways for the province of Ontario and determine the benefits and impacts of a diversified, low carbon fuels strategy to achieve GHG reduction commitments.

Guidehouse is uniquely positioned to provide EGI with industry-leading analytic capabilities, decarbonization thought leadership and utility strategy, as well as access to economy-wide models and tools that are necessary to generate robust quantitative analysis of the energy system in Ontario. We have a deep understanding of the future role of gas in a decarbonized world which informs the appropriate framing for scenarios and guides the analysis, as demonstrated in our industry leading Gas for Climate, low carbon 2050 strategic work[1].

We are confident the Guidehouse solution will further empower EGI with innovative and practical insights about jurisdictional decarbonization. Our goal is to work with you and provide a policy platform from which to build a practical decarbonization roadmap for the province and a long-term strategy that cements the sustainability and resiliency of the gas infrastructure business.

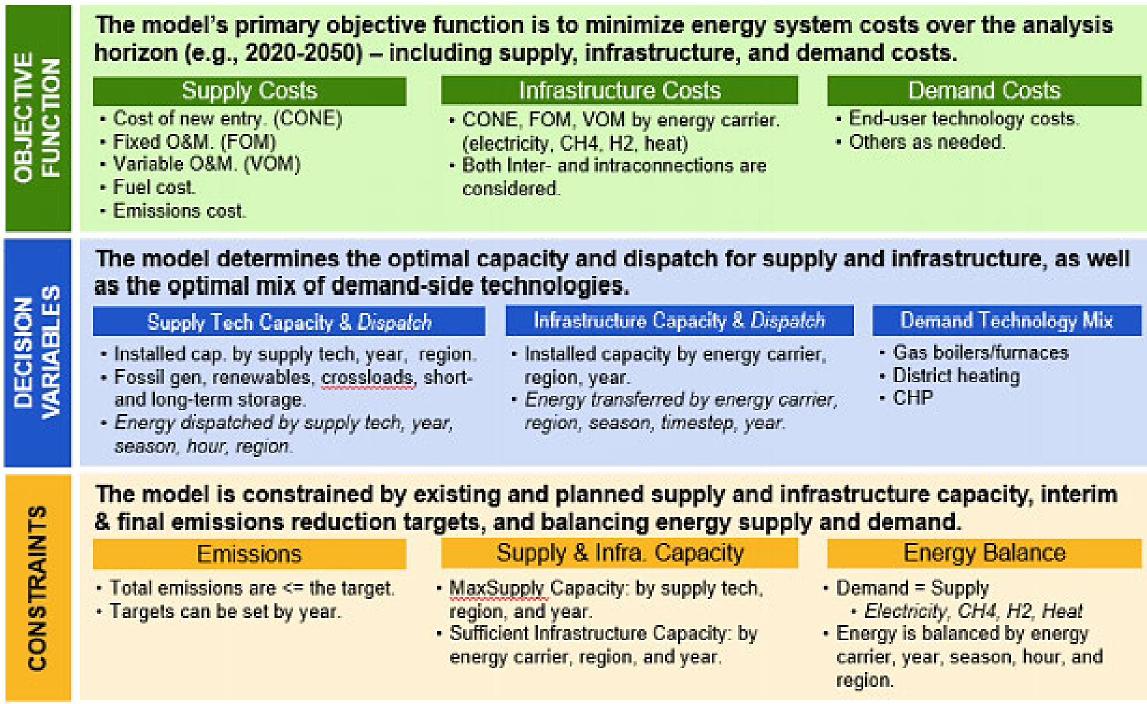
Our core team is based in Canada and has delivered multiple provincial and national-level analyses of low carbon futures in this country and in Ontario. Our proposed low carbon pathways SME (Craig Sabine) has experience in low carbon scenario analysis going back to 2005; developing one of the first national level assessments of GHG abatement curves and the impacts on energy use and process emissions across economic sectors for the National Roundtable on the Environment and Economy (NRTEE). Our leadership team are senior, highly experienced and have recently conducted extensive analyses in Canada and globally, offering insights on the low carbon opportunities for jurisdictions from British Columbia, to Sweden and New York, as well as the associated societal cost impacts of decarbonization strategies.

Our solution leverages our in-house and proprietary ***Low Carbon Pathways*** (LCP) model (see Figure 1 below), combined with our deep industry knowledge and expertise with electricity and natural gas utility systems and related commodity markets. We have developed a powerful model to determine key energy flows, regional abatement opportunities and GHG impacts of clean energy supply, as well as demand-side GHG mitigation initiatives at the sectoral, sub-sectoral and end-use levels. Our analytic platforms also enable hourly and coincident energy peak capabilities, to ensure that the key energy system impacts are viewed holistically, and real costs are captured to better uncover more optimal low carbon and net-zero futures. Our LCP model produces a forecast of the costs and benefits of each scenario that can be shared and understood by stakeholders including government, the regulator and customers.

We recently completed a first of its kind analysis to determine the societal costs of low carbon pathways, inclusive of peak energy system investment requirements, utility rate impacts and stranded asset costs in the province of British Columbia, for FortisBC.[2]

[1] Gas for Climate: A Path to 2050 Link
[2] Pathways for British Columbia. Link

Figure 1. Low Carbon Pathways (LCP) Model Conceptual Design



Addressing Your Needs

For EGI, we will deliver an augmented decarbonization analysis of the Ontario energy sector that leverages learnings and data from our prior work. Guidehouse offers a tested approach to support EGI with this very important work for the province.

In alignment with many of our past analyses, decarbonization pathway scenarios will be developed to determine the GHG and cost impacts and test feasibility of differing approaches that are supportive of provincial decarbonization goals. The study will provide EGI with key support for internal energy transition planning efforts, including EGI's critical and current rebasing proceeding that will thrust EGI toward the short term 2030 GHG target. Robust decarbonization analysis can also support establishment of scope 3 GHG emission reduction targets, and Integrated Resource Planning (IRP) work (i.e. the consideration of non-pipe solutions as alternatives instead of our traditional infrastructure).

Our analysis will also offer insight for new regulatory structures and policy mechanisms needed to mitigate the risks associated with decarbonization. Specific and measurable guidelines are needed now so that utilities can demonstrate their assets complement the future energy system.

The Guidehouse solution is based on deep collaboration between Guidehouse and EGI, using workshops to determine the best data sources and discuss the key factors to consider in bounding the clean energy resources (CERs) and initiatives that will be modelled. We will build up a profile of CER initiatives and apply them against cross-sectoral energy demand scenarios to identify key opportunities to deliver GHG reductions in the economy.

Transformative CER potentials will be established, as only fully transformative pathways will support the achievement of 2050 targets. These transformative potentials will be bounded by reasonableness, guided by our experience conducting dozens of similar analyses and having a strong feel for the challenges and costs.

Why Guidehouse

Guidehouse is uniquely positioned to provide support to EGI on low carbon pathways and offer an analytic study that will provide deep insight and practical next steps. Our team is extensively experienced in Canada's energy sector, with low carbon pathways modelling and highly familiar with the Ontario context, based on our prior fuels sector technical study as part of the 2016 LTEP process, our widely known Achievable Potentials Study work with IESO and OEB, as well as extensive analysis of the provincial electricity sector policy, costs and programs.

Globally, Guidehouse pioneered a new direction toward energy sector decarbonization — transforming the net zero conversation from one where gas utilities were seen as an impediment, to one where they are part of the solution. We orchaestrated a revolutionary concept together with the *Gas for Climate* coalition resulting in a broadly accepted vision, by stakeholders, for a low carbon gas sector.

We have current models ready to be deployed that will allow for the greatest possible efficiency for EGI over the limited number of months available.

Figure 2. Key Guidehouse Benefits to EGI

WHY GUIDEHOUSE	VALUE TO EGI	WHY GUIDEHOUSE	VALUE TO EGI
Proven experience in developing quantitative low carbon scenario models	Pre-established modelling platform and data sources, as well as practical implementation experience to delivery visionary ideas	Extensive clean energy supply use case development, including RNG and hydrogen supply initiatives	Incorporates leading industry thinking, knowledge of multi-jurisdictional policy and technical approaches
Successful, ongoing working relationships in Ontario	Guidehouse is known and trusted to major stakeholders such as the OEB, the MOE and the IESO, improving our ability to engage and facilitate the discussion	Specific familiarity with your energy systems and industrial growth sector	Provides increased context to desired outcomes, deliverables, and regulatory needs
Independent and neutral position in the market	Our analysis is vendor and technology-agnostic, which supports external engagement and offers the Province genuine and pragmatic advise	Real world successful planning, engineering, and system operations	We have the energy industry experience, deepening our analysis for you and where policy sets the landscape for success

1. Approach to Scope of Work

EGI requires an objective analysis of key pathways to Ontario's carbon neutrality. These pathways include both electrification-focused scenarios and scenarios underpinned by the use case of clean gas fuels and the associated resilient, flexible, and affordable infrastructure.

A scenario-based, *Pathways Assessment* is a critical element to build an understanding of the potential roles for gas and the ways that the gas infrastructure can be leveraged to cost-effectively meet the decarbonization objectives of Ontario.

The analysis will identify cost-optimized decarbonization pathways for the broader energy system (both gas and electric) within the constraints defined by the future scenarios, e.g., full electrification of the system or balanced electrification and gas use. ***The pathways will articulate the potential timeframes to achieve desired reductions, identify key elements of societal and system costs of implementation, assess the impacts on electric grid demand/capacity and determine the peak demand cost impacts. Our analysis will also describe the risks of stranded assets using quantified modeling of decarbonization measures.***

We envision a study and tool that can help EGI plot a cost-optimized future energy system in Ontario and ensure key insight into how decarbonization goals can be delivered, considering:

- Affordability
- Peak energy demand impacts
- Clear pathways for *hard to electrify* sectors to participate in the future system
- Maintenance of resilience and reliability in the face of changing customer demands and increasing frequency of extreme weather conditions

Our collaborative approach will ensure that EGI receives objective analysis with outcomes linked to your overarching company strategy and addresses a triple bottom line, sustainable approach inclusive of people, planet, and profit.

We understand that the speed and accuracy of the deliverables will be critically important to the success of this project. To address this need, Guidehouse has built a team of dedicated staff with deep skills delivering gas decarbonization strategies across North America and deep expertise of the energy system in Ontario. We have an existing tool, our **Low Carbon Pathways (LCP) model**, that is ideally suited for assessing gas decarbonization pathways and exploring the role of gas supply and transport infrastructure. Our LCP model has proven its value to gas utility clients through recent project work in North America and Europe and can be deployed and adapted to the Ontario energy system very quickly.

1.1 Task 1. Project Initiation

Directly following contract execution, the Guidehouse team will launch the project through the project initiation phase with a kickoff meeting. The project initiation task will encompass the first week of delivery, including a kickoff workshop with the EGI team to ensure that an appropriate future vision for the assignment is established to guide the project through the entirety of the delivery schedule.

Task 1. Summary & Highlights	
Key Questions to be Answered:	• How will two (2) analytic scenarios be defined to capture the range of possible decarbonization pathways for Ontario? • What are the end goals/expected outcomes and critical objectives of this study? How is success defined? • What input data and assumptions are required by the LCP model? What data will be requested from EGI in order to begin pathway modelling?
Key Deliverables	**A PowerPoint deck** including the following: • Finalized description of the two (2) scenarios and sensitivities to be included in modeling analysis. • Summary methodology, modelling approach and LCP modelling configuration for Ontario • Detailed list of all input data required, proposed data sources, data gaps (if any), and data request to EGI
Expected EGI Involvement	Participation in a project kickoff workshop to establish the project goals, scenario definitions, key sensitivities, and appropriate communication strategies.

The two key activities in Task 1 include a kickoff meeting with the EGI team and agreement on Guidehouse's proposed modeling configuration of our Low Carbon Pathways (LCP) model for Ontario's energy system.

Kickoff Meeting: The objectives of the meeting will be to review the scope of work, to agree on the process for data collection, to finalize the scenario definitions to be included in the modeling analysis, and to agree on the final timeline for key meetings and submission of deliverables.

Topics to be discussed / decisions to be made at the kickoff meeting:

- Report table of contents (for purpose of Task 5)
- Final agreement around scenario definitions and sensitivities
- Confirmation of Task 2 data collection approach and Task 3 modeling approach
- Expected trends in the Ontario energy system that will be fundamental to the analysis
- Final agreement to timeline of key meetings and deliverable submission

Guidehouse will prepare notes documenting all decisions made in the kickoff meeting and which will be delivered to the Enbridge team within two (2) days following the kickoff meeting.

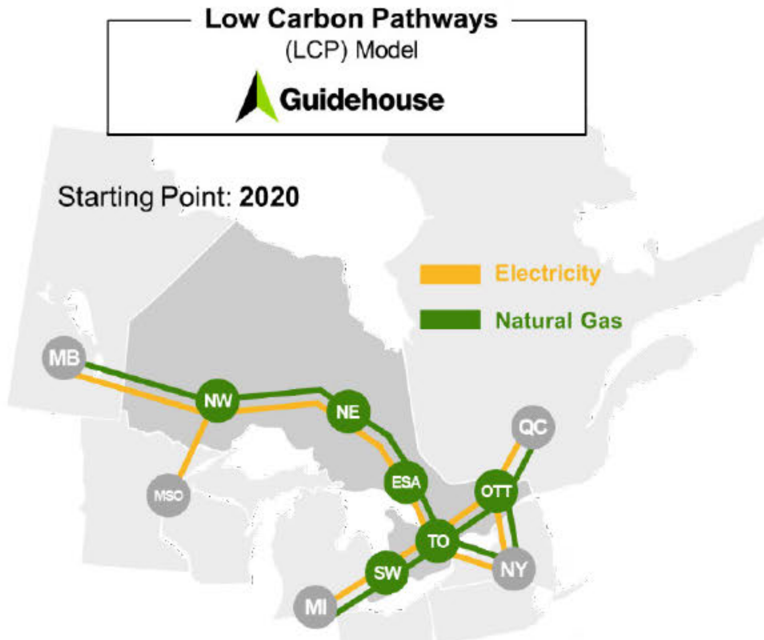
Pathways Modelling Configuration: Our proposed modelling approach will leverage our in-house, energy systems **Low Carbon Pathways (LCP)** model to simulate the decarbonization of the energy system in Ontario through 2050. Our LCP model is ideally suited for this project and for developing decarbonization pathways for energy utilities. The LCP model is an integrated capacity expansion and dispatch optimisation model used to identify cost-effective pathways to a decarbonized electricity and gas system. A key feature of our modelling approach is that our LCP model enables zonal optimization of electricity and gas supply & transport infrastructure; by doing this it captures supply and demand dynamics across sub-regions.

Our LCP model will be configured to the unique characteristics of Ontario's gas and electricity networks, interconnections with neighboring jurisdictions, and supply-demand conditions. We have developed a conceptual configuration of the LCP model to the Ontario energy system, as illustrated below. This configuration is based on approximately 5-6 Ontario zones and 4-5 neighboring regions –to reflect current-day and future energy imports and exports. As part of a very integrated continental system of natural gas pipelines and markets, the characterization of Ontario's gas sector will need to be carefully considered to provide details and analytic insight, without boiling the ocean.

The final number of zones will be determined based on discussion with EGI and will reflect an agreed aggregation of the IESO's 10 electrical zones. The analysis will model an integrated energy system made up of the existing electricity and methane (natural gas) systems, along with an emerging hydrogen system in the future. The analysis timeframe stretches from 2020 to 2050, with 10-year intervals – e.g., 2020, 2030, 2040, and 2050.

Proposed Low Carbon Pathways (LCP) Model Configuration for the Ontario Energy System

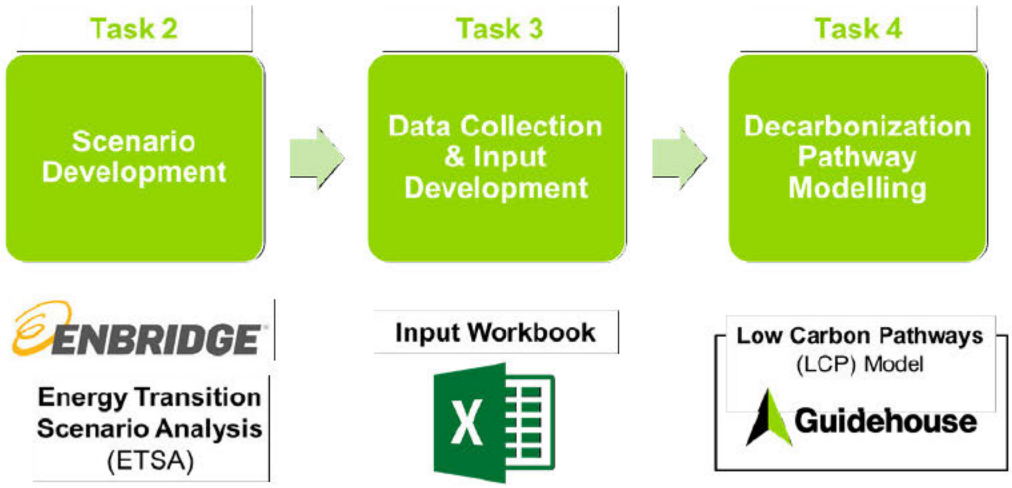
- **Geographic Scope**: 5-6 Ontario zones + 4-5 neighboring regions
- **Energy Systems**: Electricity, Natural Gas, RNG and Hydrogen
- **Interconnections**:
  - Existing electricity and natural gas interconnections within ON and with neighboring regions.
  - Hydrogen: Option to repurpose methane interconnections or build new hydrogen interconnection.
- **Modelled Years**: 2020, 2030, 2040 and 2050
- **Intra-Annual Temporal Resolution**: 5 representative days (4 seasons and a winter peak-day)



The kickoff meeting will include a detailed presentation of our modelling approach, our proposed process for leveraging EGI's existing ETSA scenarios, data needs and the sources of data we propose to use, key modelling boundaries and considerations we believe to be essential for successful calibration of the LCP model. We will provide an initial view on high-profile / high-impact sensitivities. These individual elements are discussed in detail in the following sections:

- **Task 2** (Scenario Development)
- **Task 3** (Data Collection & Input Development)
- **Task 4** (Decarbonization Pathway Modelling)

Figure 3: Overall Modelling Methodology



1.2 Task 2. Scenario Development

During Task 2, Guidehouse will work with EGI to define and characterize the scenarios to be analysed. The main objectives of this task include:

1. Review of existing scenarios emerging from EGI's Energy Transition Scenario Analysis (ETSA) and development of a plan to consider and align with the LCP analysis.
2. Determining the suitability and alignment of the ETSA's Electric Pathway and Diversified Pathway as the basis and foundation for the scenarios used in this study; and
3. Proposing modifications and adjustments to the ETSA scenarios (if needed) to develop this study's Electric and Diversified scenarios and their associated 2025-2050 forecasts of gas (and electricity) demand.

Task 2. Summary & Highlights	
Key Questions to be Answered:	• What input data and assumptions are available to understand prior characterisation of ETSA pathways? • How can the ETSA pathways be leveraged to define the two (2) analytical scenarios for this study and what modifications will be required? • What is the high-level definition of each of the two (2) pathways to be modeled in this study?

Key Deliverables	**A PowerPoint deck** including the following: • Finalized description of the two (2) scenarios and sensitivities to be included in modeling analysis. • Summary of modifications / differences between ETSA scenarios and the two (2) scenarios for this study
Expected EGI Involvement	Participation in a scenario characterization workshop to develop a common understanding of how to leverage the ETSAs. This will include providing Guidehouse with relevant identified data from EGI.

Based on our current understanding of EGI's ETSA, we expect the existing *Electric* and *Diversified Pathways* scenarios to align with leading practice in decarbonization pathway thinking. In general, we assume the ETSA scenarios to align relatively well with common trends found in traditional 'high electrification' and 'balanced' scenarios. Some of these common elements are described below:

- **Electric Pathway:** High electrification scenarios are generally characterized by continued decarbonization of electric generation and high levels of electrification across buildings, industry, and (particularly) transportation. Natural gas, blended with RNG and combusted with carbon capture and storage (CCS), is limited to high temperature industrial end-uses. RNG and hydrogen are used as industrial feedstocks while biofuels play a major role meeting non-electrified heavy transportation demand, with minimal role for RNG and hydrogen.

- **Diversified Pathway:** Balanced or Diversified scenarios are generally characterized by complete decarbonization of electric generation, along with more moderate levels of electrification, focusing primarily in cost-effective building and industrial heating, and light- and medium- transportation applications. Low carbon fuels, including RNG and hydrogen, play a more prominent role in buildings, transport, and industry, leveraging existing or upgraded gas infrastructure investments. Biofuels play a more limited role in meeting demand for medium- and heavy-duty transportation.

GAS FOR CLIMATE
A path to 2050

European Hydrogen Backbone

The scenarios outlined in the RFP, and in this proposal, are generally congruent with our standard approach to define scenarios for LCP analysis.

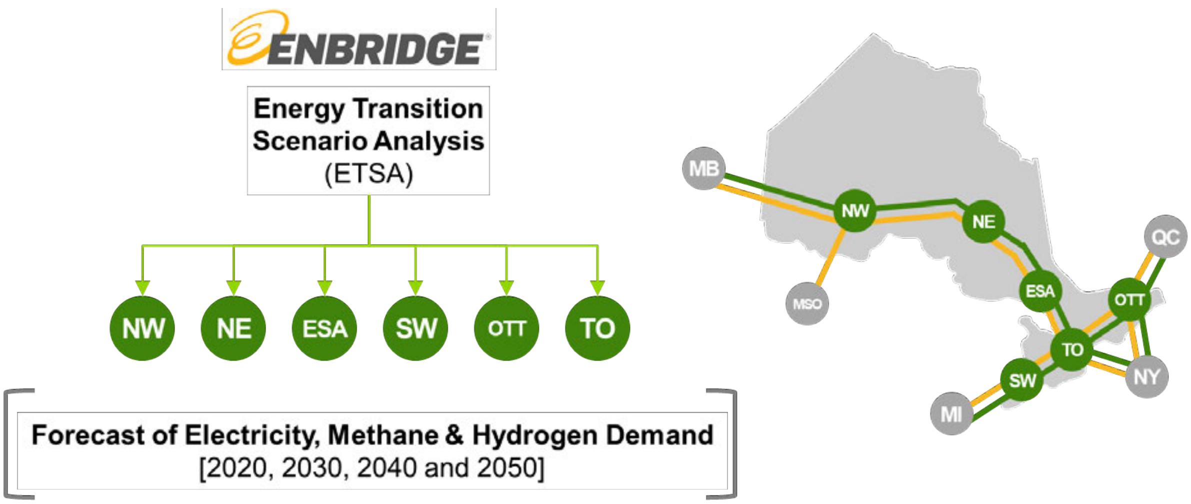
You will see similar scenarios with regional tailoring in our ***Gas for Climate*** (follow link), inclusive of the **European Hydrogen Backbone** work in the EU, as well as a soon to be released public report examining pathways to achieve the **New York Climate Act**.

Alignment between this study and the ETSA project will be critical for a highly impactful and strategic study. Our understanding is that the ETSA scenarios are – at the provincial level – inherently consistent with Ontario's economy-wide 2050 GHG reduction targets, Ontario's interim target of 28% reduction by 2025, and EGI's own clean energy and emissions reductions targets.

Regionalization: Based on our proposed modelling approach – adopting 5-6 Ontario zones – and our understanding of how important the regional / zonal dimensionality is to EGI, we will map the regions used in the ETSA scenarios to the 5-6 Ontario regions we have proposed (or agree to during project initiation). If ETSA scenarios already incorporate some regionalization, we will work with EGI to align our analysis to these definitions where possible. We will work with EGI to agree on the number of Ontario regions used in this study and the geographic scope of each of those regions. A proposed approach for regionalization is presented in Figure 4.

If the ETSA scenarios are not regionalized but rather only defined at the Ontario-level, we will propose a regionalization approach to define electricity and gas demand for individual economic sectors across regions. If this is needed, we will propose to use proxies for each demand sector (e.g., population for the buildings sector, transit hubs for the transport sector, etc.) as well as leverage previous analyses (such as the IESO conservation Achievable Potential study, which Guidehouse also conducted).

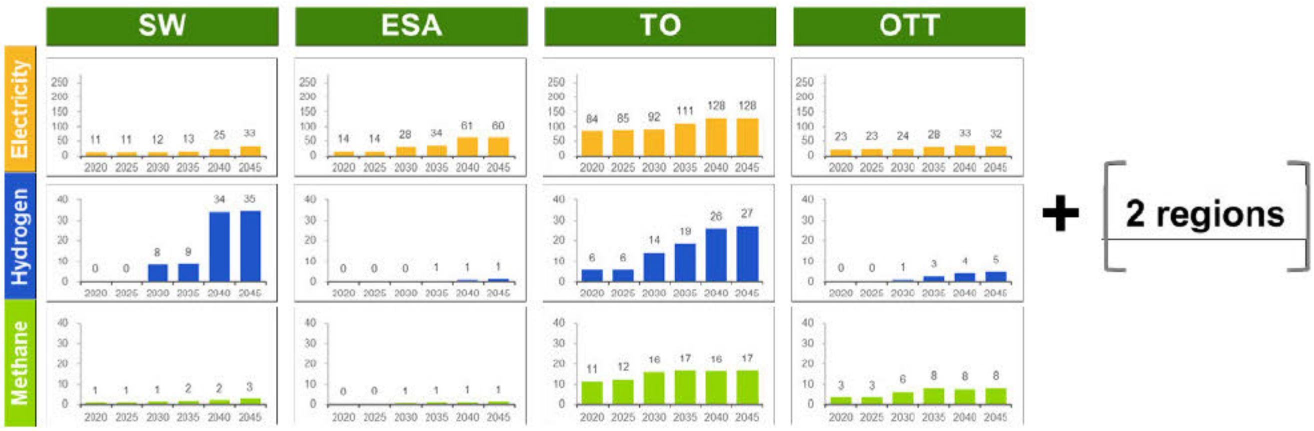
Figure 4: Possible Breakdown of EGI's ETSA Scenarios into Individual Ontario Zones



The final product of the regionalization exercise will be a transformation of the ETSA demand forecasts of electricity, methane, and hydrogen demand (2020-2050) into regional forecast of demand for each individual zone based on the economic and customer characteristics of each zone. Figure 5 shows what this will ultimately look like: a 2020-2050 forecast of electricity, hydrogen and methane demand for each region.

The importance of "regionalizing" demand is that this will serve as the basis for determining whether electricity and gas transmission infrastructure will have to be expanded in the future, or in the case of hydrogen, where gas transmission pipelines will have to be repurposed to accommodate hydrogen.

Figure 5: Illustrative 2020-2050 Forecast of Electricity, Hydrogen and Methane Demand



A workshop will be facilitated with the objective of generating a rich discussion of the decarbonization technologies incorporated in the ETSA scenarios and the role of RNG and hydrogen in buildings, transport, and industry.

Scenario Characterization Workshop: During the model characterization workshop, the Guidehouse team will lead the EGI team through an exercise to “deep dive” into each of the relevant ETSA scenarios, challenge underlying drivers and building a common understanding of how each scenario was developed and considerations as part of this Decarbonization Pathways study. This detail on the scenarios will be important to the Guidehouse team’s ability to replicate the ETSA scenarios as closely as appropriate in this work.

1.3 Task 3. Data Collection & Input Development

Immediately following initiation and aligning on the scenario definitions, Guidehouse’s team will begin the process of data collection to inform the LCP modeling. This process will be led in close collaboration with the EGI team to discuss and vet all of the model inputs and ensure common understanding of the impacts to final modeling results.

Task 3. Summary & Highlights	
Key Questions to be Answered:	• What does the Ontario energy system look like today? What is the existing electricity supply mix? What are the energy export/import dynamics in Ontario? • What electricity and gas transmission capacity is available today within Ontario regions? And with neighboring regions? • What investments in electricity / gas supply and transport infrastructure are expected in the future in Ontario? And in neighboring regions? • How much RNG supply potential is available in Ontario? What are the future potential sources of hydrogen in Ontario and neighboring regions?

Key Deliverables	• A **PowerPoint deck** presenting all major data inputs and assumption including:
	  • Techno-economic parameters for electricity/gas supply technologies and transport infrastructure costs.
	  • Existing and forecast electricity supply capacity, transmission capacity, interconnection capacity between Ontario regions and with neighboring regions.

Task 3. Summary & Highlights	
Expected EGI Involvement	Participation in a scenario data and design workshop to agree on data sources. This will include providing Guidehouse with relevant identified data from EGI.

Given on our past experience performing decarbonization pathway analyses, we have established a structured and streamlined process for data collection. We have a standardized Excel-based "input workbook" that gathers all inputs and assumptions required for the pathway's analysis.

The Guidehouse team that will support EGI in this engagement has extensive experience in decarbonization pathway projects, as well as with the Ontario energy sector and the critical data required to deliver this project. Key system and demand data will be drawn from EGI, as well as other publicly available sources such as:

- IESO Annual Planning Outlook
- Ontario's Integrated Achievable Potentials Study (completed by Guidehouse)
- Planning Outlooks & Historical Electricity Demand (Hydro Quebec, NYISO and MISO)
- Natural Gas Transmission & Distribution Expansion Projects (EGI and Union)
- Historical Gas Demand (ON and neighboring regions)
- Statistic Canada Data Sets

We will be able to get a head-start in data collection by leveraging an extensive dataset of techno-economic assumptions for electricity / gas supply and transport infrastructure from past projects (e.g., costs for electrolysers, SMR+CCS, RNG via anaerobic digestion, biomass gasification, new and repurposed hydrogen transmission pipelines).

In addition to techno-economic parameters for energy technologies, the input workbook also collects inputs to characterize the current state of the Ontario electricity and gas system, as well as planned / expected developments in the energy technology mix up to 2050.

The structure of the input workbook and the scope of data required is summarized by Table 1.

Table 1: Data Needs from LCP Input Workbook

Category	Tab #	Input Data	Energy Carrier
Demand	1.1	**2030, 2040, 2050 forecast of demand** [by region] • Electricity demand [2020, 2030, 2040, 2050] • Methane demand [2020, 2030, 2040, 2050] • Hydrogen demand [2020, 2030, 2040, 2050]	Elec., CH_4, H_2
Demand	1.2	**Hourly demand profiles by sector & network load profiles** • Hourly profiles for each season [x4] and a winter/summer-peak day.	Elec., CH_4, H_2
Supply	2.1	**Existing supply capacity** • 2020 Electricity Supply Mix • 2020 Gas Supply Mix [e.g., imports, domestic biogas production via anaerobic digestion, etc.)	Elec., CH_4
Supply	2.2	**Planned new capacity** {2030, 2040, and 2050] • IESO Planned Capacity Additions	Elec., CH_4
Supply	2.3.	**Planned capacity retirements** [2030, 2040, and 2050] • IESO Planned Capacity Retirements	Elec., CH_4
Supply	2.4	**RNG & Hydrogen Supply Potential** [2030, 2040, and 2050] • Define max limit on RNG supply via anaerobic digestion • Define max limit on RNG supply via biomass gasification • Define max limit on blue and green hydrogen supply • Define max limit on hydrogen storage capacity (salt caverns, aquafers, etc.)	CH_4, H_2
Supply	2.5	**Techno-economic parameters for supply technologies** [CAPEX, OPEX, FOM, VOM; 2030, 2040 and 2050] • <u>Electricity</u>: Onshore wind, hydrogen-fired CCGT / OCGT, RNG-fired CCGT / OCGT, battery storage, etc. • <u>Hydrogen</u>: Blue H2 (SMR + CCS) and green H2 (dedicated vs. curtailed renewables), H2 storage (salt caverns, aquafers, etc.) • <u>Methane:</u> Anaerobic digestion, biomass gasification	Elec., CH_4, H_2
Infrastructure	3.1	**Existing Interconnection capacities** [2020] • In-between Ontario zones [GW] • In-between Ontario and neighboring regions [GW]	Elec., CH_4
Infrastructure	3.2	**Planned interconnection capacities** [2030, 2040, and 2050] • In-between Ontario zones [GW] • In-between Ontario and neighboring regions [GW]	Elec., CH_4
Infrastructure	3.3	**Techno-economic parameters** new transmission lines • Overhead AC, Underground/Overhead HVDC	Elec.
Infrastructure	3.4	**Techno-economic parameters** new / retrofit pipelines [20, 36 and 48-inch pipelines] • Underground / above-ground new methane pipelines • Underground / above-ground new hydrogen pipelines • Repurposed hydrogen pipelines • Hydrogen compression stations	CH_4, H_2
General	4.1	**Economic parameters** (WACC, carbon prices)	n/a

With our previous experience developing decarbonization pathways for gas utilities, we have developed an extensive dataset of techno-economic parameters for hydrogen and RNG production technologies. We plan to get a kickstart the data collection process by leveraging techno-economic parameters developed in previous projects. For example, Table 2 shows cost assumptions (from 2025 to 2045) for green and blue hydrogen (via electrolysers and SMR+CCS) and for RNG (via AD and biomass gasification).

Table 2: Example of Techno-Economic Parameters for Supply Technologies

Kick-Starting Data Collection: Hydrogen & RNG Supply Technologies

Hydrogen:
- Electrolysers
- SMR+CCS

Year	Cost Component	Unit	Electrolysers	SMR + CCS
2025	CAPEX	[kEUR/MW]	600	1530
	Fixed O&M	[kEUR/MW/y]	12	45.9
	Variable O&M	[kEUR/MWh]	0	5.5
	Lifetime	[year]	25	25
	Efficiency (LHV)	[%]	67	69
2035	CAPEX	[kEUR/MW]	400	1340
	Fixed O&M	[kEUR/MW/y]	8	40.2
	Variable O&M	[kEUR/MWh]	0	5.5
	Lifetime	[year]	25	25
	Net Efficiency	[%]	70	69
2045	CAPEX	[kEUR/MW]	300	1300
	Fixed O&M	[kEUR/MW/y]	6	39
	Variable O&M	[kEUR/MWh]	0	5.5
	Lifetime	[year]	25	25
	Net Efficiency	[%]	73	69

RNG:
- Anaerobic Digestion
- Biomass Gasification (BioSNG)

Year	Cost Component	Unit	Anaerobic Digestion	Biomass Gasification
2025	CAPEX	[kEUR/MW]	2165	2595
	Fixed O&M	[kEUR/MW/y]	216	265
	Variable O&M	[kEUR/MWh]	43	52
	Lifetime	[year]	25	20
2035	CAPEX	[kEUR/MW]	2049	2119
	Fixed O&M	[kEUR/MW/y]	178	227
	Variable O&M	[kEUR/MWh]	38	47
	Lifetime	[year]	25	20
2045	CAPEX	[kEUR/MW]	1934	1642
	Fixed O&M	[kEUR/MW/y]	141	190
	Variable O&M	[kEUR/MWh]	33	42
	Lifetime	[year]	25	20

Based on the LCP input workbook needs presented above, we have already identified the specific gaps in data that must be bridged before we can begin pathway modelling. Table 3 below lists out the subset of input data that Enbridge can help us with to fill those gaps; this includes five specific areas of EGI input.

For all other data needs required for the LCP input workbook, we have already identified publicly available data resources from the IESO, OEB, the Government and past studies to be used. As described above, we also bring an extensive dataset of techno-economic parameters for electricity, hydrogen and methane supply and transport infrastructure investments.

Table 3: Preliminary Data Request for Enbridge

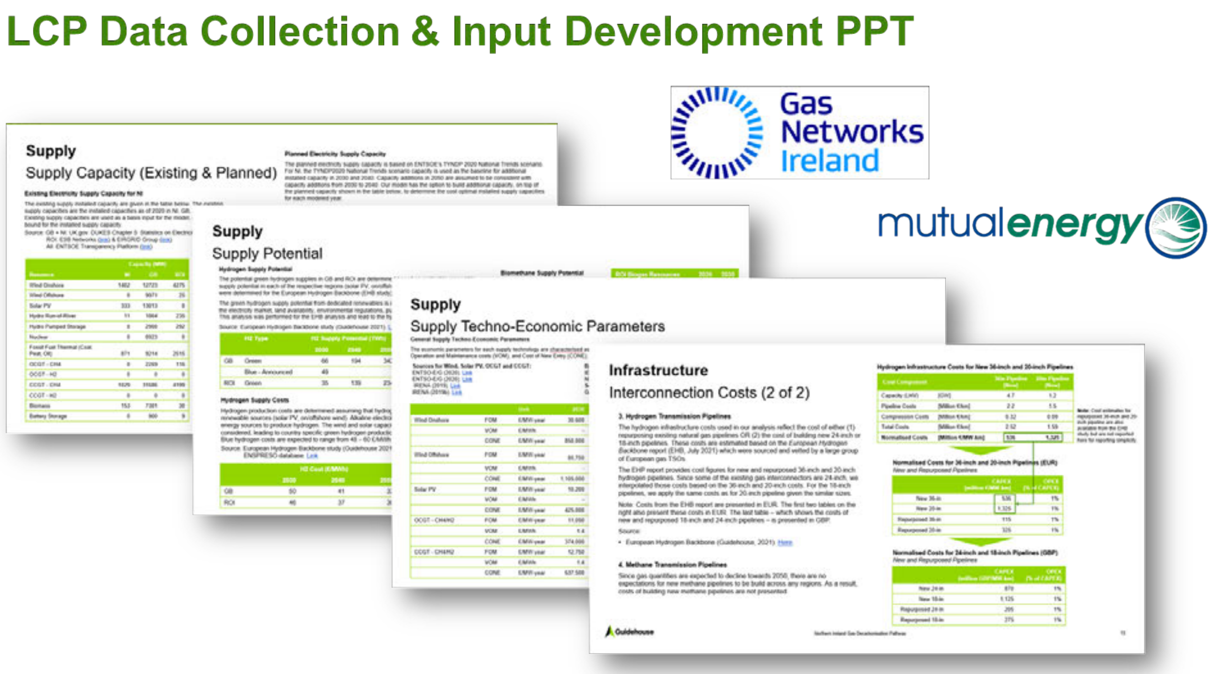
ENBRIDGE

Category	Tab #	Input Data	EGI Source / Data Need
Demand	1.1	**2030, 2040, 2050 forecast of electricity, CH4 and H2 demand**	EGI ETSA Scenarios
Demand	1.2	**2019/2020 hourly gas demand profiles by sector & total network**	Ontario 2019/20 Hourly Gas Demand
Supply	2.1	**Existing gas supply capacity (imports, RNG, etc.)**	Ontario 2019/20 RNG supply capacity
Infrastructure	3.1	**Existing gas interconnection capacities**	2020 Gas Regional interconnection Capacities
Infrastructure	3.2	**Planned gas interconnection capacities**	Planned Regional Interconnection Expansion

Guidehouse's well-vetted process for collaborative data collection and analysis will ensure that the model outcomes are credible and provide meaningful insights. Our data collection process is both iterative and collaborative, relying on a series of client workshops, to ensure that our LCP model incorporates the most appropriate inputs for Ontario and neighboring regions and those are reviewed / approved by EGI.

The deliverable from Task 3 will be a PPT deck presenting all major data inputs and assumption listed above. Figure 6 shows a recent LCP data collection PPT deck produced for a consortium of gas utility clients.

Figure 6: Illustrative LCP Data Collection & Input Development PPT Deliverable



1.4 Task 4. Decarbonization Pathways Modelling

In Task 4, we will use Guidehouse's LCP model to develop cost optimized decarbonization pathways for Ontario's energy system between 2020 and 2050 based on two scenarios: Electric Pathway and Diversified Pathway. We also propose to analyze decarbonization pathways based on 2-3 high-impact sensitivities.

We will quantitatively and qualitatively describe the two resulting pathway scenarios deriving insights by comparing the pathways and focusing on the contributions that can be made by an integrated electricity and gas energy system to meet Ontario's GHG reduction goals

Task 4. Summary & Highlights	
Key Questions to be Answered:	• What is the cost optimized decarbonization pathway for each of the two scenarios? • What are the key societal cost considerations of each of the two pathways by 2050 and test the cost competitiveness of each scenario for key milestone years? • What are the opportunities and feasibility of RNG, hydrogen, and other low carbon fuels to support Ontario's energy needs while achieving GHG emission reduction targets?

Key Deliverables	• Quantitative and qualitative summary of the cost optimized pathways, preliminary results prepared for preliminary results workshop and final results for final results workshop; for main scenarios and sensitivity scenarios.
	    • Gas & Electricity Supply Mix [2030, 2040, 2050] – *e.g., RNG, hydrogen, wind, solar, etc.*
	    • Gas & Electricity Transmission Infrastructure [2030, 2040, 2050] – *e.g., repurposed new / pipelines, transmission line, etc.*
	    • Total Gas & Electricity Network Investment Costs [2030, 2040, 2050]
	    • Hourly Energy Demand & Peak Demand [2030, 2040, 2050]
	    • Pathway risks, challenges, opportunities, low-regret investments & actions
	• Databook of all modeling results

Expected Enbridge Involvement	Day-to-day review and discussion of modeling interim modeling results. Participation in a half-day workshop to review preliminary results and half-day workshop to review final modeling results

Guidehouse proposes to use our LCP model to develop cost optimized decarbonization pathways for each scenario and sensitivity. The LCP model will enable us to provide unparalleled insight into the role of low carbon gas and gas system infrastructure in Ontario.

The configuration of the LCP model to the Ontario energy system will be defined based a selection of 5-6 Ontario regions and 4-5 neighboring regions. The model will capture changing supply and demand over time from 2020 to 2050 in each region. This regional configuration will enable us to model the optimized buildout of interconnection infrastructure between regions – whether electricity transmission lines or methane / hydrogen transmission pipelines. The hourly balancing of supply and demand is optimized on an hour-to-hour basis by using 4 representative seasonal days (x4) and summer and winter peak days (x2).

Guidehouse will configure the LCP model and complete an initial modeling run, providing preliminary results. These preliminary results will be reviewed in a half-day workshop with the Enbridge team. As is always the case with these types of modeling challenges, questions will arise following the preliminary data results review. Guidehouse will adjust and rerun the models to provide final pathways results.

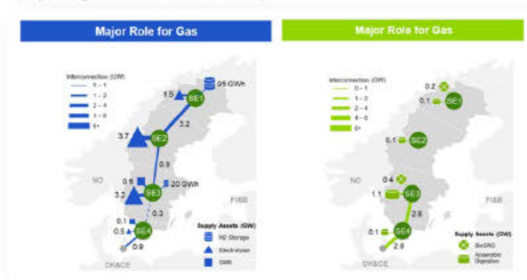
Table 4: LCP Key Model Outputs

LCP Key Model Outputs

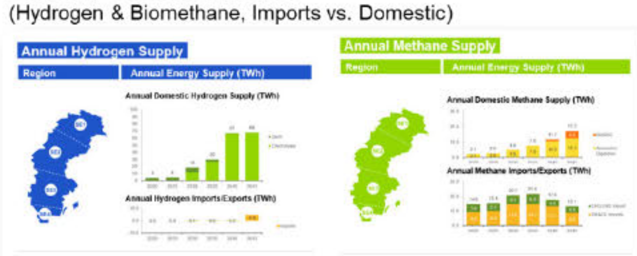
Our LCP model produces all major pathway outputs required by EGI:

- **Low-carbon and renewable gas quantities** over time (e.g., green hydrogen, blue hydrogen, AD biomethane, biomass gasification, etc.)
- **Energy system costs** including **gas and electricity network investments**:
  - **Supply capacity** (e.g., onshore/offshore wind, electrolysers, SMR, etc.)
  - **Transmission interconnections** (e.g., transmission lines, new/retrofit pipelines, etc.)
  - **Storage assets** (e.g., hydrogen storage, battery storage, etc.).
- **Timeline of investments** (2020, 2030, 2040, and 2050)

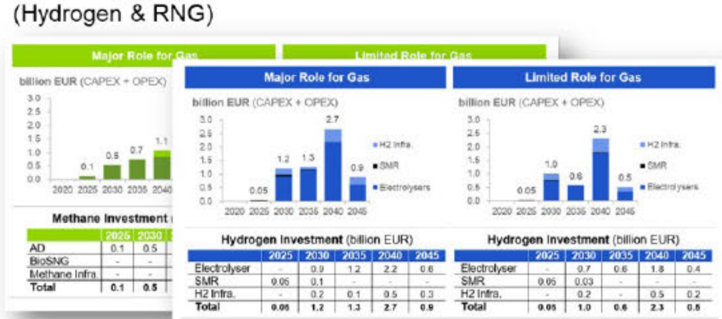
Gas Transmission Infrastructure
(Hydrogen & Biomethane)



Annual Gas Quantities
(Hydrogen & Biomethane, Imports vs. Domestic)



Gas Supply & Infrastructure Cost
(Hydrogen & RNG)



Sensitivity Scenarios: In addition to the main demand scenarios, we will also determine pathways for a set of three (3) sensitivity scenarios. We will define the set of sensitivities analysed after discussion with EGI, however, the following are potential candidate sensitivities to consider:

- **Electricity infrastructure and supply Capital Cost Risk:** Assess the impacts of varying degrees of capital cost escalation for new electric capacity and related system assets.
- **Low Electrolyser and H_2 Infrastructure Costs:** Assess the impact of low electrolyser cost and low transmission pipeline costs on the development gas infrastructure.
- **Ontario as a H_2 Exporter:** Assess the impact of Ontario acting as a hydrogen exporting regions to neighboring regions on the development of gas infrastructure.
- **Low Cost of H_2 Imports into Ontario:** Assess the impact of low-cost hydrogen supply from neighboring regions (e.g., Quebec utilising its hydro fleet for hydrogen production) on the development of gas infrastructure.

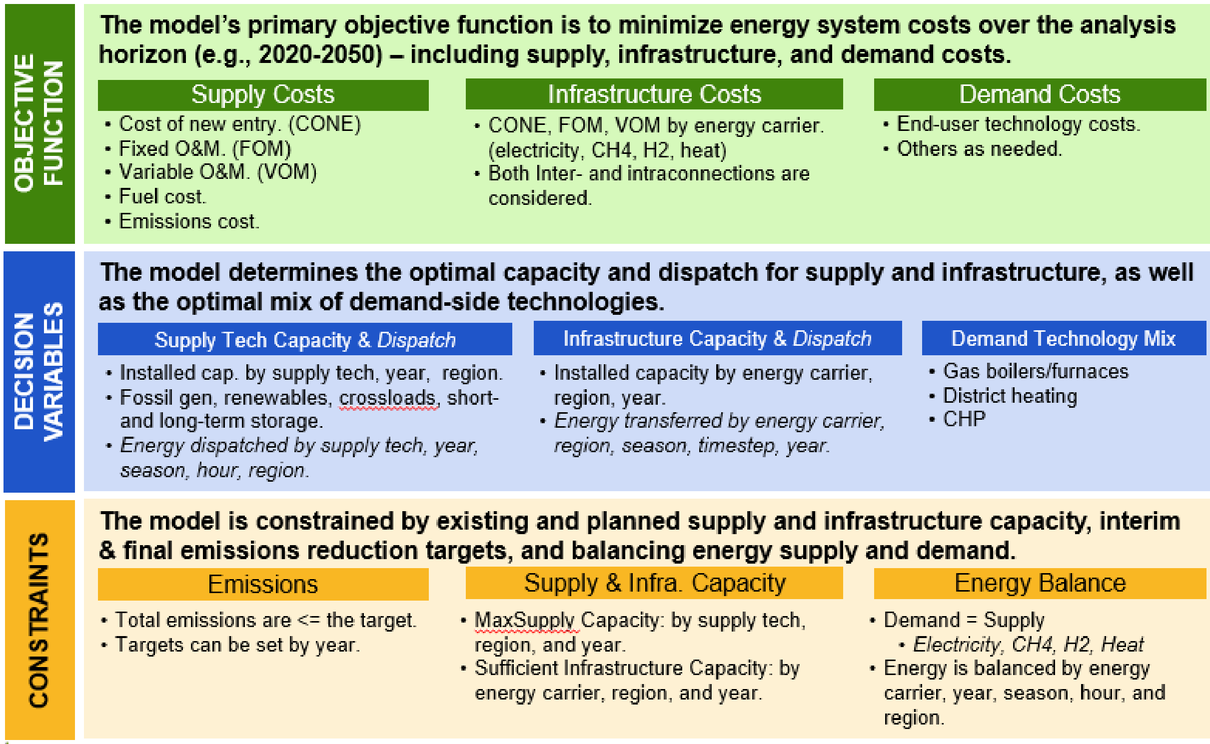
Overview of Guidehouse's LCP Model: Guidehouse's LCP model is a pathways analysis tool built to analyze how a future state develops. The model uses linear optimization to calculate the cost optimal pathway to decarbonize Ontario's energy system. Cost optimization in this case refers to the lowest likely societal cost, i.e., focusing on the total costs and benefits for society to achieve full energy system decarbonization and the critical system, equipment and stranded costs that will have the greatest impact on cost to Ontarians. Figure 7 provides an overview of the LCP model design.

The LCP model includes:

- The possibility to assess various scenarios to deliver a fully decarbonized energy system. The model enables comparison between different decarbonized end state scenarios across a region's entire energy system based on system-wide production costs. This enables us to identify the societal value of achieving a carbon neutral energy system with a (growing) role for low carbon gases in combination with electricity.

- A multi-year cost optimized pathway analysis to deliver intermediate (2030, 2040) and end state (2050) objectives. The LCP model also enables testing of sensitivities and alternative pathway options.

Figure 7: High-Level LCP Model Design



The LCP model's primary objective function is to minimize energy system costs over the analysis horizon (e.g., 2025-2050) – including supply, infrastructure, and demand costs. The cost-objective function optimizes overall system costs but can be configured to optimize for any subset of costs including network/grid costs, or cost to end users for equipment with known cost curves.

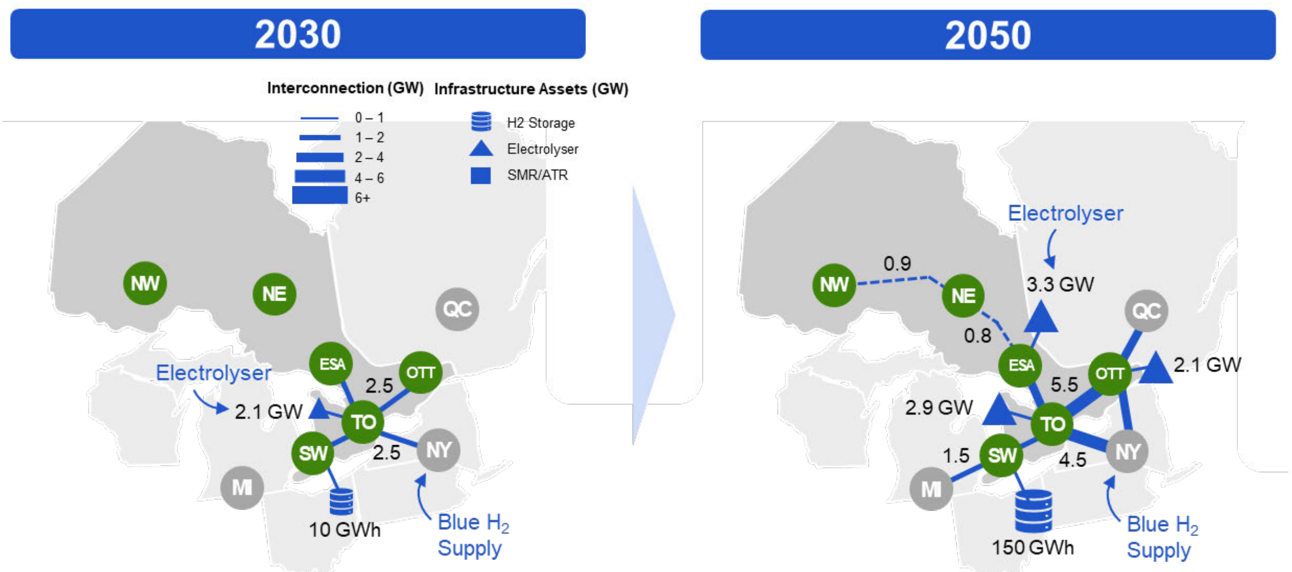
The cost analysis is based on societal cost considerations of the pathways, representative of the total cost of achieving pathway outcomes (GHG abatement) to Ontarians as a whole assuming reasonable market development and market access. The LCP model considers cost in three broad categories on an annual basis:

- **Supply costs** including upfront costs, generation costs, ongoing fixed costs, ongoing variable costs, fuel costs, and emissions costs
- **Infrastructure costs** capture the cost of transmission and distribution (T&D) infrastructure across the power and gas sectors. Guidehouse's team has also developed an approach to estimate the system cost of *stranding infrastructure* and supply investments that can result from non-integrated policy and investment decision making.
- **Demand costs** can capture the cost of end-user equipment including heating systems in buildings, insulation, and industrial equipment. These components of incremental societal cost will be captured based on materiality and in alignment with our past approaches to cost analyses.

The model determines the optimal capacity and dispatch for supply and infrastructure to meet electricity, methane and hydrogen demand. Individual supply technologies or transmission infrastructure options can be 'turned' up or down and 'switched' on or off depending on scenario parameters. The model is constrained by existing and planned supply and infrastructure capacity, interim and final GHG emissions reduction targets, and balancing energy supply and demand.

To illustrate some of the key outputs from the LCP pathways modelling, Figure 8 shows a hypothetical hydrogen infrastructure pathway for Ontario from 2030 to 2050. Our analysis will produce 2030, 2040 and 2050 snapshots of the development of hydrogen infrastructure across Ontario – including GW of installed electrolyser and SMR capacity, GWh of hydrogen storage required, repurposed and/or new hydrogen transmission pipelines, etc. All of these results will be produced for each individual Ontario region.

Figure 8: Illustrative Hydrogen Infrastructure Pathway (2030, 2050) for Ontario



Our understanding is that one of EGI's main interests is in the development of supply and infrastructure costs for each of the pathways analysed (whether scenarios or sensitivities). Our analysis will produce pathway costs figures, like the ones presented below by **Figure** 9 and **Figure 10**.

This figure shows the hydrogen infrastructure pathway costs developed for a group of gas transmission and distribution companies in a recent engagement.

Figure 9: Example Hydrogen Infrastructure Investments

Investment Costs for Hydrogen Infrastructure Development (2025-2045)

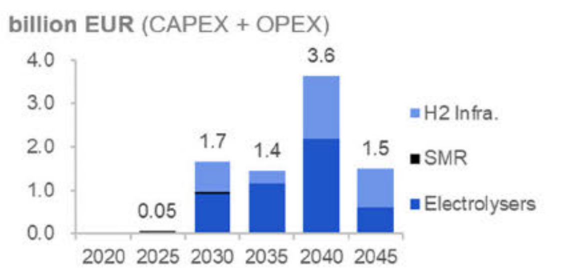
The figures show the hydrogen infrastructure investment determined in a **recent project for group of gas transmission and distribution companies**. Two decarbonization scenarios were assessed; both in the same context as EGI's Diversified and Electric pathway scenarios.

The tables below show the investment required to scale up hydrogen infrastructure from 2025 to 2045. Investments include CAPEX and OPEX of electrolysers, SMR+CCS and hydrogen transmission pipelines.

- Our analysis determined the **Diversified** scenario required the buildout of 36-inch hydrogen pipelines across c.1,400km; for a total investment of **EUR 3.3. billion**.
- In comparison, the **Electric** scenario required 20-inch pipelines over 1,000km and 36-inch pipelines over 400km; a total investment of **EUR 2.6 billion.**

Hydrogen Infrastructure Investment (Billion €)

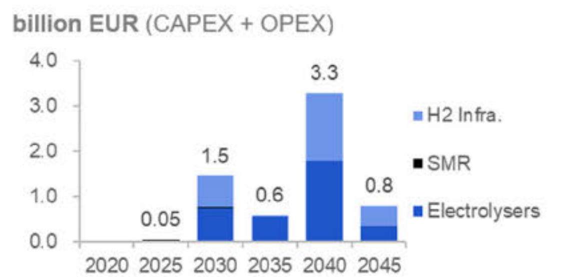
Diversified Pathway



Hydrogen Investment (billion EUR)

	2025	2030	2035	2040	2045	Total
Electrolyser	-	0.9	1.2	2.2	0.6	**4.9**
SMR	0.05	0.1	-	-	-	**0.1**
H2 Infra.	-	0.7	0.3	1.4	0.9	**3.3**
Total	**0.05**	**1.2**	**1.3**	**2.7**	**0.9**	**8.3**

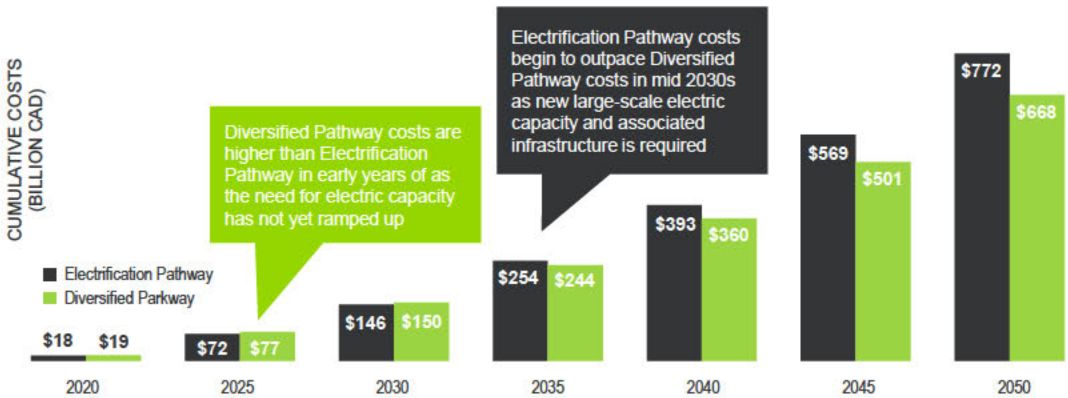
Electric Pathway



Hydrogen Investment (billion EUR)

	2025	2030	2035	2040	2045	Total
Electrolyser	-	0.7	0.6	1.8	0.4	**3.5**
SMR	0.05	0.1	-	-	-	**0.1**
H2 Infra.	-	0.7	0.0	1.5	0.4	**2.6**
Total	**0.05**	**1.5**	**0.6**	**3.3**	**0.8**	**6.2**

Figure 10: Example Pathway Cumulative Costs



An additional set of illustrative outputs of the LCP model are presented below in **Figure 11** and **Figure 12.**

Figure 11: Illustrative Example Model Outputs

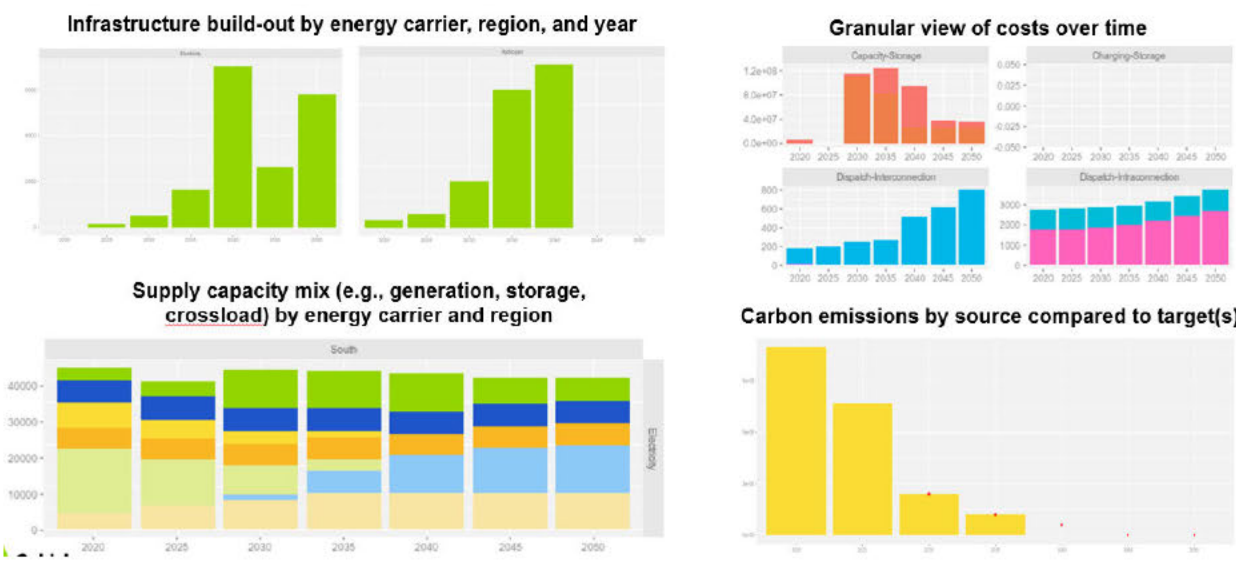
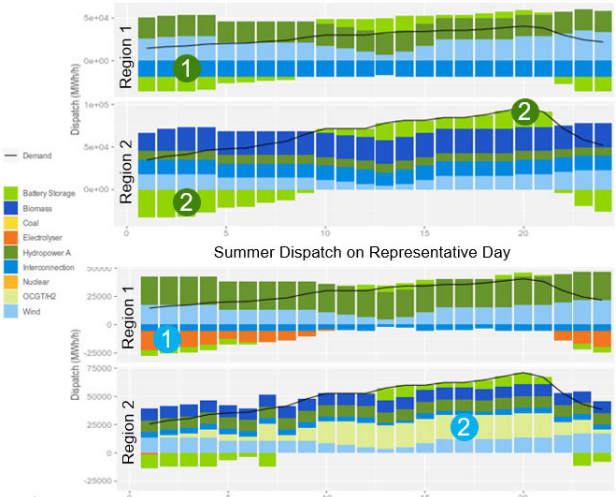


Figure 12: Illustrative Scenario Insights



High Electrification Scenario

1. Excess wind and hydro generated in Region 1 is sent via electric transmission to Region 2.
2. Region 2 uses the excess electricity to charge batteries in the morning, which then discharge in the evening to meet demand.

Scenario costs total $X billion, driven largely by electricity generation and transmission infrastructure, and battery costs.

Balanced Gas System Scenario

1. Excess wind and hydro are converted to hydrogen using an electrolyser in Region 1, then transported via pipeline to Region 2.
2. Region 2 stores the hydrogen in a reservoir, then dispatches it to gas/hydrogen turbines to meet electricity demand.

Scenario costs total $Y billion, driven largely by electrolyser, hydrogen transmission, and hydrogen reservoir costs.

1.5 Task 5. Reporting

Guidehouse is providing two reporting options for EGI's consideration.

Option 1: Draft Report in PPT format and Final Report in Word format.

Guidehouse will prepare a PPT report to the November 1st deadline. The report will be structured to facilitate internal and external feedback sessions which will be completed by EGI. Guidehouse's experience is that PPT format is more conducive to focusing feedback on important conceptual elements of the project methodology, inputs, scenarios, risks, and conclusions. A Word formatted report tends to elicit significant editorial and formatting comments/feedback. Guidehouse followed the PPT report format during its project with FortisBC. The executive of FortisBC appreciated the short time commitment required to review the report and the ability to have a focused discussion on key concepts and conclusions when the PPT report was presented to them.

Guidehouse will prepare a draft final report in Word format within 10 days of receiving EGI's comments from the stakeholdering process that EGI will conduct in November and early December. EGI will need to provide a concise and organized set of stakeholder comments to Guidehouse.

EGI will provide its comments to the draft final report by December 20th. Guidehouse will create a next-to-final report for EGI's review, for editorial and formatting purposes only, before the end of December. Guidehouse will incorporate EGI's editorial and formatting comments in the final report for delivery on January 4th. Guidehouse would typically encourage multiple drafts and comments stages but limited time between when the stakeholdering process is completed and when the final report is due dictates a well-structured process and somewhat rigid timeline.

In order to meet for EGI and Guidehouse to meet final deadline of January 4th, each partner will need to commit to prompt review and turnarounds.

Option 2: Draft and Final Reports in Word format.

Guidehouse will prepare a Word formatted draft report for November 1st.

Guidehouse will prepare a draft final report in Word format within 10 days of receiving EGI's comments from the stakeholdering process that EGI will conduct in November and early December. EGI will need to provide a concise and organized set of stakeholder comments to Guidehouse.

EGI will provide its comments to the draft final report by December 20th. Guidehouse will create a next-to-final report for EGI's review, for editorial and formatting purposes only, before the end of December. Guidehouse will incorporate EGI's editorial and formatting comments in the final report for delivery on January 4th.

In order to meet for EGI and Guidehouse to meet final deadline of January 4th, each partner will need to commit to prompt review and turnarounds.

Option 1 vs. Option 2

The price and schedule for each of the two options is the same. EGI can choose either of the two options at any time up until early October or EGI and Guidehouse can agree to a hybrid option based on how the project unfolds.

Proposed Final Report Outline (estimated to be 60-80 pages total)

In the remainder of this section, we present a proposed outline for the final deliverable report which will be updated based on input from Enbridge during the project initiation phase. Should EGI choose Option 1 from above, the PPT format draft report will include summary slides for all aspects of the proposed outline except perhaps for Appendix B – Detailed Model Inputs.

- Executive Summary (2-3 pages)
  - Recommendation of the least cost option to reach net-zero emissions
  - Summary of the most critical implications to Enbridge business and questions that remain to be explored
- Introduction (1-2 pages)
  - What critical questions did this work address?
  - Considerations for how the data should be used
  - Scenario definitions
- Outcomes of the Pathways Assessment (6-9 pages)
  - Electrification
  - Diversified
    - For each scenario a graphic description will be provided that describes the optimal pathway modeled through the Pathways Assessment and the following details will be provided:

        - Total CAPEX costs for the owner and total societal costs, for achieving target by 2050 (short-term 2030 and long-term 2050)
        - Impacts on electric grid demand / capacity
        - Risks of stranded assets (loss of gas demand and changing customer segments served)
        - Abatement potential from baseline year
        - Pathway opportunities and risks
        - System Reliability opportunities, challenges and limitations
- Implications of the Pathways Assessment to Enbridge' Gas Business and Ontario's broader Energy System (10-12 pages)
    - Review of current energy system and policy framework in Ontario
    - Policy framework that would be needed to implement optimal pathway
        - Identification and characterization of critical drivers that will be required to drive either pathway
    - Opportunities and feasibility of H2, RNG and other low carbon fuels
    - Review of energy imports/exports and expected changes or implications of pathways
    - Pathways ability to adjust to sudden or extreme weather conditions
    - Evidence to support the role of both the electricity and gas systems in achieving low cost decarbonization in Ontario
    - High level commentary on the possible environmental impacts/benefits, including to land, water, waste management (including nuclear waste), associated with each scenario.
- Conclusions (3-4 pages)
    - Recommendation of the least cost option to reach net-zero emissions
    - Summary of the implications in Ontario
    - Key questions that remain unanswered or were identified for further investigation through the course of the analysis
    - How Enbridge should use the information from this study
- Appendix A: Methodology (8-12 pages)
    - Detailed description of the methodology used to provide the documented results, including a description of the LCP model
- Appendix B: Detailed Model Inputs (8-12 Pages)
    - Documentation of all analysis inputs and links to data sources

1.6 Task 6. Stakeholder Engagement (if necessary)

We have a specifically designed team of senior thought leaders and experienced facilitation and strategy consultants to support any stakeholder engagement which occurs following the study. Andrea Roszell (Director-in-Charge) has recently supported stakeholdering of the FortisBC Pathways study with multiple organizations across BC and North America including the BCUC, BC Hydro and the NWGA.

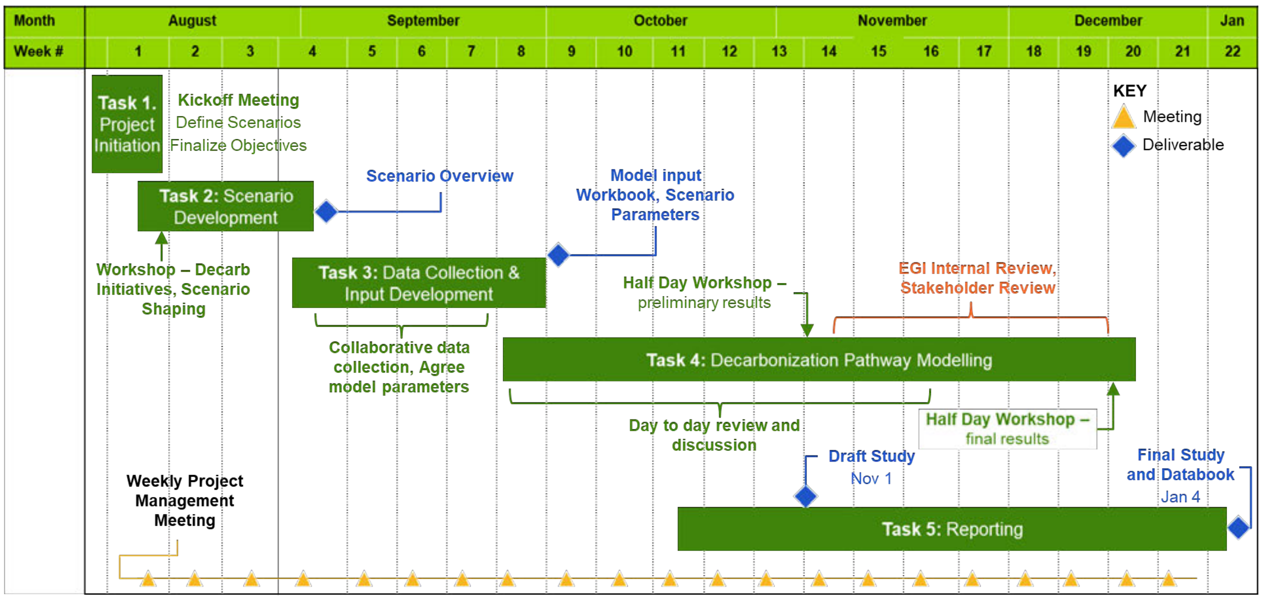
Guidehouse proposes to leverage the Transformation Readiness and Strategic Vision (TSV) Model™ to develop internal and external alignment on the study results and key outcomes. The model leverages facilitated discussion across and around the organization to determine the critical areas of strategic focus that are required for decarbonization. TSV is based on three core principles:

1. **Multiple and comprehensive points of view** – includes opportunity for senior leadership, management and staff layers of the organization to contribute ideas
2. **Focused Discussion** – through interview and workshop instruments, we focus discussion on key trends and conversations that matter
3. **Strategic Alignment** – aligns outcomes with provincial policy, corporate strategic direction and integrated energy system views

2. Project Schedule and Deliverables

The proposed schedule ensures that the defined scope of work is delivered on time and within budget. Our project management approach combines detailed project planning, scheduled client communications, and detailed reviews.

Table 5. Proposed Project Schedule



2.1 Assumptions

The key assumptions made in the proposed project schedule are listed below.

- Guidehouse's project schedule is based on EGI's start date indicated in the RFP. A delay in project start could affect the schedule as shown. We will work with you to amend the schedule and extend delivery dates as appropriate.
- This proposal's project schedule assumes EGI's timely review and approval of any project materials provided by Guidehouse. For this defined scope of work, timely review is defined as no more than 3 business days.
- All data used in the development of scenarios for analysis will either be publicly verifiable or agreed to for use as part of the analysis by both parties, should any public report be required.

3. Our Team

Guidehouse has assembled a team of highly qualified and experienced professionals who can complete a decarbonization pathways study that EGI can be confident will support EGI's business planning activities and external stakeholder discussions. To effectively manage this assignment and establish a project governance, control and quality assurance mechanism, Guidehouse will implement the following team and approach.

The Guidehouse team will be overseen by Craig Sabine, who leads Guidehouse's Canadian energy practice and who has extensive low carbon economy modeling and pathways experience, going back to 2003 during development of Canada's initial climate change policy and emissions pricing policy platforms. Craig will work closely with the Director-In-Charge and the team as a SME, offering guidance, project facilitation and QA/QC.

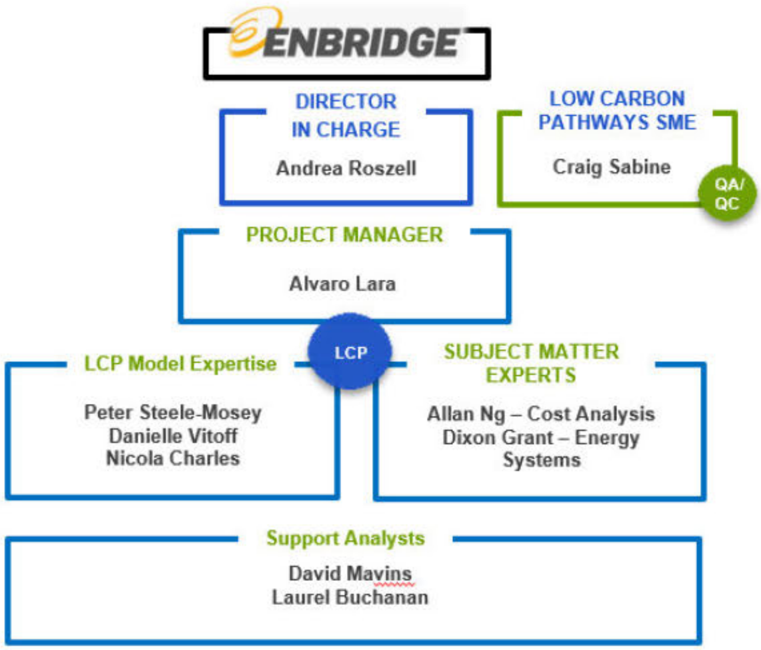
Andrea Roszell, a Director in Guidehouse's Canadian practice, will serve as engagement manager and Director in Charge for this effort. Andrea will be available to EGI at any time to address strategic direction of the project, quality, performance and concerns and issues as they arise. Andrea led Guidehouse's low carbon pathways engagement with FortisBC.

Alvaro Lara will serve as the project manager. He will be the key point of contact for the EGI team. Alvaro will establish communications and schedule regular and strategic meetings, as required, working closely with the EGI program manager to ensure the project stays on schedule, within the proposed budget and achieves critical deliverables. Alvaro's decarbonization pathway experience includes engagements with gas transmission and distribution companies in the UK and mainland Europe. Alvaro is very familiar with the context of the Ontario energy system as he has supported engagements with most major Ontario energy stakeholders.

Our team organization in Figure 13 ensures that the right level of resources is deployed to meet the completion deadline. This structure leverages highly skilled experts to span the capability sets required for this scope of work. Biographical sketches for key team members follow in Craig Sabine and Dixon Grant, who have both been involved in five other engagements, summarized in Appendix A, with EGI over the last twelve months, will provide continuity with those projects and an understanding of EGI's strategy and operations.

Table 6. Professional resumes for the senior team members are attached with our submission as a separate document.

Figure 13: Project Team Organization



Craig Sabine and Dixon Grant, who have both been involved in five other engagements, summarized in Appendix A, with EGI over the last twelve months, will provide continuity with those projects and an understanding of EGI's strategy and operations.

Table 6. Expertise and Experience of Key Team Members

Consultant | Title | Project Role	Education	Qualifications and Experience
Craig Sabine Director Toronto Project Role: Director in Charge	• MBA, Queens, Smith School of Business • BES, Environment and Resource, University of Waterloo	**19 years of experience that includes:** Low carbon economy modelling, pathways analysis and GHG mitigation abatement curves Policy analysis of market-based emission reduction mechanisms, energy efficiency programs and clean supply standards Regulatory support and utility corporate strategy Transactions support and M&A for over $40 billion in power and natural gas assets Integrated resources planning initiatives for nearly every major provincial utility in Canada Economic analysis and BCA

Consultant | Title | Project Role	Education	Qualifications and Experience
Andrea Roszell Director Toronto Project Role: Director in Charge	• Master of Science, Chemical Engineering (Queen's University) • B.S., Honours, Chemical Engineering (University of Waterloo)	**15 years of experience that includes:** Low carbon economy modelling and pathways analysis Transportation Electrification EE and DSM program planning and evaluation Microgrid and renewable energy project assessments Business case development and market assessment of emerging energy technologies Financial analysis and asset valuation
Danielle Vitoff Associate Director Project Role: Decarbonization Pathways Strategy	• BA, Environmental Design, Architectural Program, Montana State University • BA, Liberal Studies, Environmental Studies Option, Montana State University	**10+ years of experience that includes:** Sustainability, decarbonization, and strategic planning for utilities, corporations and governments. Led the delivery of the recently completed AGF Resilience Study. Led teams, as the project manager, to support decarbonization plans for multiple natural gas utilities including, GHG assessments, decarbonization roadmaps, and evaluating business impacts to support rate case filings. Led teams in delivering climate risk and sustainability strategies for utilities, Fortune 100 companies, and top 10 U.S. cities.
Alvaro Lara Managing Consultant Utrecht Project Role: Project Manager	• MSc. Climate Change, Management and Finance (Imperial College Business School, UK) • BEng. Mechanical Engineering (University of Toronto)	**7+ years of experience that includes:** Electricity and gas network decarbonization and energy system analyses Grid modernization strategy, long-term investment plans, cost-benefit analyses Demand-side management (energy efficiency) planning, strategy, and long-term forecasting Electric mobility adoption, strategy, data analysis
Allan Ng Managing Consultant Toronto Project Role: SME – Cost Analysis	• MBA, Smith School of Business, Queens • CPA, Canada • B.Comm COOP in Accounting, University of Calgary	**12 years of experience that includes:** Asset life-cycle modelling for energy transition Financial and utility revenue requirement modelling to determine customer rate impact under low carbon scenarios Developed stranded asset methodology and modelling for FortisBC low carbon pathway Lead development of electric transportation business cases and economic analysis Leads North America transaction advisory in supporting investors and large corporate in acquisitions focused in energy transition

Consultant | Title | Project Role	Education	Qualifications and Experience
Dixon Grant Managing Consultant Toronto Project Role: SME – Energy Systems	• BComm, Queen's University • BSc., Biology, Queen's University	**5 years of experience that includes:** Development of clean growth pathways for natural gas utilities, including the assessment of GHG reduction potential and costs of low carbon technologies (RNG, transportation, heat pumps, energy efficiency, etc.) Canadian market lead for wholesale energy market modelling and price forecasts Financial due diligence and valuation for large infrastructure projects and M&A Electricity load forecasting GHG accounting and assessment for industrials
Peter Steele-Mosey Associate Director Toronto Project Role: LCP Model SME	• BA (H), Queen's University • MA, Economics – Applied Econometrics, University of Guelph	**14 years of experience that includes:** • Development of the Ontario Fuels Technical report for the Ontario Ministry of Energy., a scenario analysis of potential approaches for decarbonizing Ontario's combustible fuel sector. • Development of two consecutive (in 2016 and 2019) scenario analyses for FortisBC to explore the consequences of significant structural changes in load drivers on the existing reference forecast of load. • Load forecasting and load forecast support for Canadian, US, and Middle Eastern utilities. • Econometric impact evaluation of price pilots, time-differentiated tariffs, demand response and energy efficiency programs.
Nicola Charles Senior Consultant Toronto Project Role: Support	• Bachelor of Engineering, Applied Mathematics and Mechanical Engineering, Queen's University	**3 years of experience that includes:** • Econometric evaluation of energy efficiency and demand response programs across North America • Measure characterization and modeling for EE and DSM potential studies • Program design and BCA for EE programs • Adoption, traffic and charging station site modelling using advanced optimization and GIS to support electric transportation business cases and economic analysis for utilities
David Mavins Consultant Toronto Project Role: Support	• BASc, Queen's University	**2 years of experience that includes:** • EU Hydrogen Backbone decarbonization scenarios analysis • BC Hydro electric vehicle fast charger rate design • Industry decarbonization pathways • Forecasting hydrogen system development • Strategy with respect to distributed energy resources

Consultant | Title | Project Role	Education	Qualifications and Experience
Laurel Buchanan Consultant Toronto Project Role: Support	• BASc, Queen's University	**2 years of experience that includes:** • Regulatory filing support on a variety of topics including EVSE ownership and natural gas demand forecasting • GHG accounting and target setting for corporates • Power asset valuations and clean energy due diligence • Energy market research and analysis • Survey development and analysis and stakeholder interviews

4. Pricing

Guidehouse will complete the scope of work detailed in this proposal for a fixed fee of [redacted]

Guidehouse will complete any additional work at rates and/or fixed fees to be agreed between Guidehouse and EGI.

Assumptions:

- In order to meet the January 4, 2022 deadline for a final report, EGI will have two opportunities to provide input to the draft report. Once after EGI completes its stakeholdering process and once after Guidehouse provides an updated report based on EGI's stakeholder-based comments.
- This proposal is valid for 90 days from date of submittal.
- This project will be executed under the Consulting Agreement between Enbridge Gas Inc and Guidehouse signed January 28, 2021.
- EGI will be responsible to schedule their employees to attend all meetings, workshops, and interviews.
- When Guidehouse personnel are working onsite, EGI will provide workspace (e.g., conference rooms, individual spaces) and internet access as needed.
- It is assumed currently that stakeholder engagement will be performed by EGI. Should Guidehouse be required for stakeholder engagement and public facing report necessary, incremental fees may apply.

Appendix A. Qualifications

Our relevant experience, which is highlighted below, allows us to start fast and become productive immediately. In addition to quick startup, the lessons we have learned through a series of recent decarbonization strategy engagements will allow our team to offer deeper insights and more comprehensive results.

A.1 EGI Experience

We understand the Ontario energy context, policy environment and both the electricity and natural gas systems in the province. We have extensive decarbonization analysis experience across major jurisdictions and gas utility service territories, and we will proceed with this important work with a keen understanding of the EGI context having current and recent project work experience supporting the organization's planned 2022 rebasing application. Our work with EGI has included the following projects and we encourage your team to gauge our rigorous and collaborative consulting approach and team-based delivery style with your colleagues, who *include Jason Gillet, Steve Dantzer, John Gillis, Safi Junaid, Hulya Sayyan, Elena Chang* and *Briana Hamilton.*

Project	Gas Storage Blind RFP	Gas Supply Planning Approach Benchmarking	Avoided Costs Calculation	Load Forecast Approach Benchmarking	Corporate Share Service Cost Allocation Review
Brief Summary	Developed a process to independently procure gas storage at Dawn via RFP	Comparative analysis of industry practices related to weather and risk assumptions for gas supply planning, incl. utility best practices for design day demand modeling.	Reviewed current DSM avoided cost assumptions, methodologies, and input and provided best practice/jurisdictional review.	Examined leading practices applied by gas utilities in approaches and procedures for load forecasting	Independent review of reasonableness and appropriateness of corporate shared services cost allocation methodology

These projects have been conducted, or are in the process of being completed, by various Guidehouse teams, demonstrating our breadth of experience, knowledge of key aspects of EGI's operations and our deep capacity to deliver. Strong continuity exists with our proposed approach, with Craig Sabine and Dixon Grant having been involved in nearly all EGI work over the past 12 months.

A.2 Low Carbon Pathways Modelling

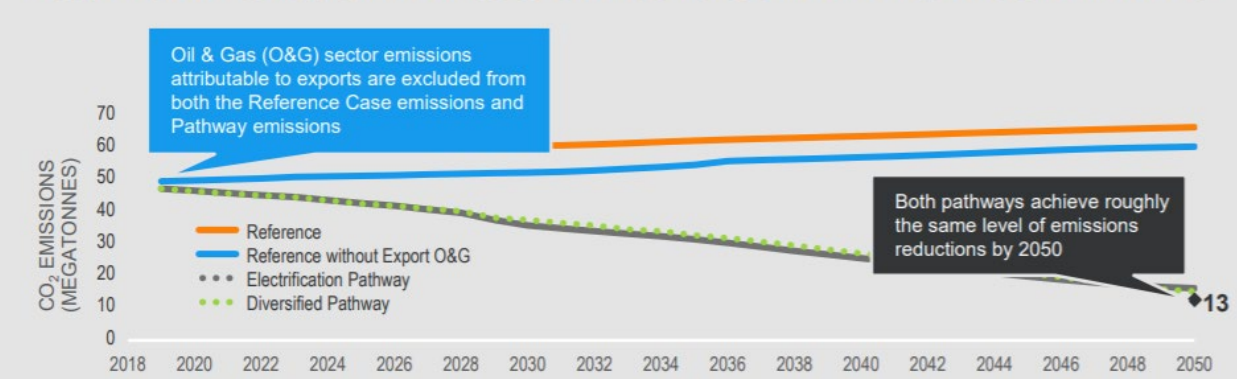
FortisBC Energy Vision 2050 Low Carbon Pathway. (2019-2020). Challenged by a highly progressive policy landscape focused on meeting Paris-aligned GHG targets for the province, FortisBC has been lobbying for natural gas to be considered as part of the solution to climate change. Guidehouse supported the utility to analyse deep carbon reduction scenarios and identify unique pathways to achieve 80% reduction targets by 2050. Pathways include a role for the reliable and low-cost natural gas system. Guidehouse partnered with whatIf?, an economy and energy modelling team, to develop and analyse comprehensive low carbon scenarios.

First, a pathway that aligns with current government policy initiatives designed to incent high electrification was examined. Secondly, a series of renewable and alternative fuels and built environment initiatives were defined and modelled to provide an optimized gas scenario. Key conclusions from the study include:

- The Electrification and Diversified Pathways both achieve significant domestic GHG reductions in-line with the provincial government's 2050 targets.
- The Diversified Pathway uses gas infrastructure and saves in excess of $100 billion by 2050

A public copy of Guidehouse's report can be found at this link.

FIGURE 10. BRITISH COLUMBIA EMISSIONS REDUCTIONS UNDER ENERGY VISION PATHWAYS



National Fuel Gas Company (NFGDC) – Guidehouse completed a scenario analysis for New York's Climate Leadership and Community Protection Act (CLCPA).

In 2019, New York State adopted the Climate Leadership and Community Protection Act (CLCPA), with the ambitious target of 85% reduction in GHG emissions by 2050 (relative to 1990). NFGDC, a natural gas utility, wanted to understand how this policy will affect different sectors' demand for natural gas and customers' annual energy costs. In particular, NFGDC was curious whether the displacement of natural gas by low-carbon alternatives fuels would improve customer energy costs

Guidehouse used our low carbon pathways model to conduct a scenario-based analysis, comparing the potential outcomes of an electrification-focused scenario to a scenario that facilitates alternative fuel development. We assessed the various GHG reduction technologies that would need to be deployed and the associated CAPEX that would be required to meet the overall goal of the CLCPA and the various requirements that the law sets out for the power sector. We also constructed representative rate models to estimate how decarbonization policies will impact customers' energy bills in Upstate and Downstate New York.

The Result: We provided an objective analysis that highlights the value of considering gas within the decarbonization portfolio to meet the CLCPA targets. Continuing to use the gas system and transitioning to low-carbon gas substitutes will reduce the cost of decarbonization for NY customers.

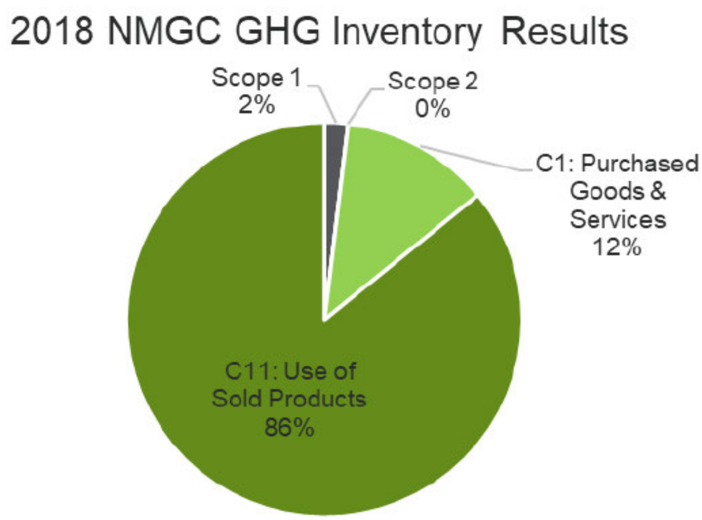
NFGDC Scenarios

	Business as Usual	Selective Electrification	Electrification Only
Achievement of GHG Reduction Target (CLCPA)	CLCPA 2050 target is not met	Yes, CLCPA target and potentially more aggressive targets are met.	Yes, CLCPA target and potentially more aggressive targets are met.
Customer Choice / Benefit	Customers continue to maintain fuel and system choice	Customers will continue to maintain some choice	Customer choice will be restricted to all-electric systems
Leveraging Existing Infrastructure	Existing infrastructure is used to the fullest extent	Much of existing infrastructure can continue to be used	Most natural gas infrastructure will be retired and extensive build out of electric infrastructure will be required.
Inherent System Resiliency / Reliability	Resiliency and reliability of current operations is maintained and potentially increased	System resiliency / reliability will be similar to the business as usual case	More costly to maintain system resiliency and reliability given the intermittent production of renewables
System Cost	Lowest system cost of the scenarios considered.	More costly than business as usual scenario, but less costly that full electrification	Significant cost for the build out of infrastructure including systems and conversion of existing systems

New Mexico Gas Company Low Carbon Pathways Roadmap – In early 2019, the Governor of New Mexico committed the State to meeting the goals of the Paris Agreement and reducing the state's GHG emissions 45% by 2030, relative to 2005. New Mexico Gas Company (NMGC) needed to understand the associated challenges and opportunities for their business and develop a new paradigm for low-carbon operation and investments.

Guidehouse led the NMGC team through three phases of work, including:

1. Development of a GHG inventory by evaluating NMGC's total emissions in 2018, the trend since 2010, and portion of the State's emissions that is related to NMGC.
2. Review of decarbonization goals and pathways, including best practices being pursued by peer utilities and clarification of the pathway to achieve the Paris Climate Agreement.
3. Development of a low-carbon roadmap, which assesses NMGC's opportunities to reduce emissions across all emissions categories identified in the GHG inventory.



The decarbonization roadmap will be included as an appendix document in NMGC's upcoming rate case, where NMGC will present the preliminary framework for their transition to low-carbon operation and the necessary investments to get there.

Nordion Energi (TSO) & Gas Distribution Companies – Gas Infrastructure Pathways for a Net-Zero Swedish Energy System –

Sweden has set ambitious net-zero target to decarbonize its economy by 2045, along with interim 2030 and 2040 targets. SwedeGas was looking to understand the role and value of gas supply and gas infrastructure in meeting these climate targets, as well how energy networks in individual regions will transition from today to 2045

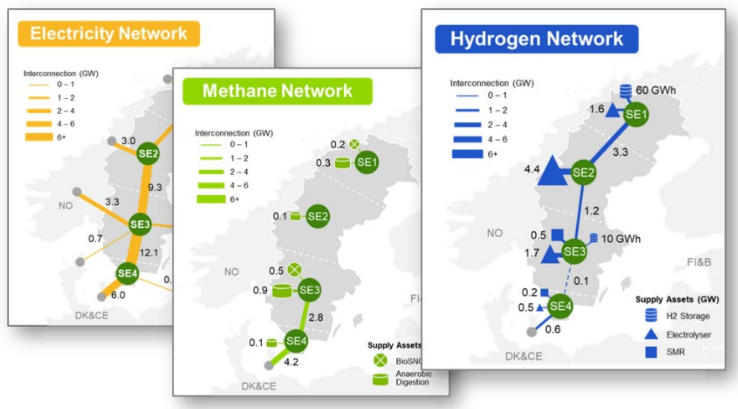
Guidehouse used its Low Carbon Pathways (LCP) model to optimize 2020-2045 decarbonization pathways for the Swedish energy system to understand the buildout of electricity, hydrogen and methane supply capacity, and associated transmission infrastructure within Swedish regions and with neighbouring regions.

Major modelling considerations included:

- Integrated capacity expansion and dispatch optimization
- Optimisation of generation, storage, and interconnections (electricity, CH4 and H2) with emissions targets
- Intra-annual temporal resolution: representative days by season
- Geographical resolution: 4 regional nodes with interconnections

REGIONAL FOCUS

- Our modelling approach was configured to **4 Swedish regions** corresponding to the existing electricity bidding zones (SE1, SE2, SE3 and SE4), and 3 neighboring regions: **Denmark and Central** Europe (**DK&CE**), **Finland & the Baltics** (FI&B), and **Norway** (NO)
- For each region, we determined a **regional cost-optimal buildout of supply capacity and interconnection infrastructure** for the electricity, hydrogen and methane networks from 2020 to 2045.



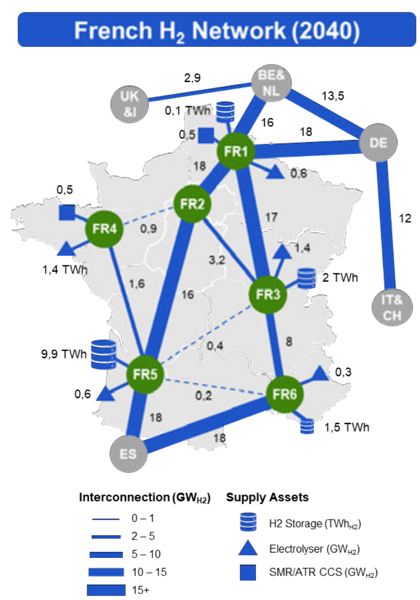
Guidehouse's report was endorsed and publicised by Nordion Energi (TSO) and the 5 Swedish Gas DNOs and distributed to Swedish policymakers and politicians.

GRT Gaz & Consortium – Hydrogen Transport and Storage Infrastructure in France – Our client needed an analysis-based assessment of the role of hydrogen transportation and storage infrastructure in the context of France's hydrogen strategy and the broader European context.

Guidehouse completed a data gathering and scenario development exercise across 4 scenarios: On-site H2 production, Ecosystèmes territoriaux, Ecosystèmes européens, and hybrid.

Guidehouse used its Low Carbon Pathways (LCP) model to calculate the costs and benefits of each scenario including investment requirements, costs of H2 delivered, cost of green H2 delivered, quantification of security of supply and annual Co2 saved.

Guidehouse developed a narrative through objective and fact-based approach to bring coherence to the complex subject.



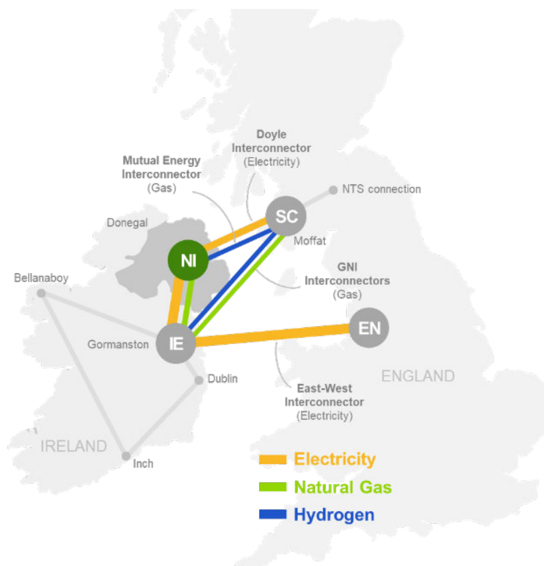
The Result:

- An analysis-based assessment of four hydrogen demand, supply, transportation, and storage scenarios to meet France's goal of 6.5GW of production by 2030
- A clear rationale on the role of hydrogen transportation and storage infrastructure and the benefits for France (investment, security, avoided CO2, societal cost saving)
- An analysis-based report with clear conclusions and assumptions presented to the CSF.

Gas Networks Ireland & Mutual Energy – Gas Networks Pathways to a Net-Zero 2050 – The Northern Ireland (NI) Government is developing an energy strategy to facilitate NI's contribution to the UK Net Zero 2050 strategy. As part of this the gas network operators of Northern Ireland (TSOs and DNOs) have been asked to develop a credible pathway to net zero for their sector.

Guidehouse used its Low Carbon Pathways (LCP) model to optimize 2020-2050 decarbonization pathways for the NI energy system.

- Geographic Scope: 3 zones; NI and neighbouring regions (ROI and GB)
- Energy carriers: Electricity, hydrogen, and methane
- Interconnections: Existing electricity and methane interconnections, and option to repurpose / build new hydrogen interconnections
- Modelled years: 2020, 2030, 2040 and 2050



Pathway outputs from the LCP model were used to develop a high-level implementation plan of near-term (2030) and long-term (2040-2050) supply and infrastructure investments by the NI gas networks

The Result: The project is underway and is expected to be completed by Q3-2021. Our report will serve as a foundation for the NI gas networks' decarbonization plans and investments over their next regulatory period (2022-2026).

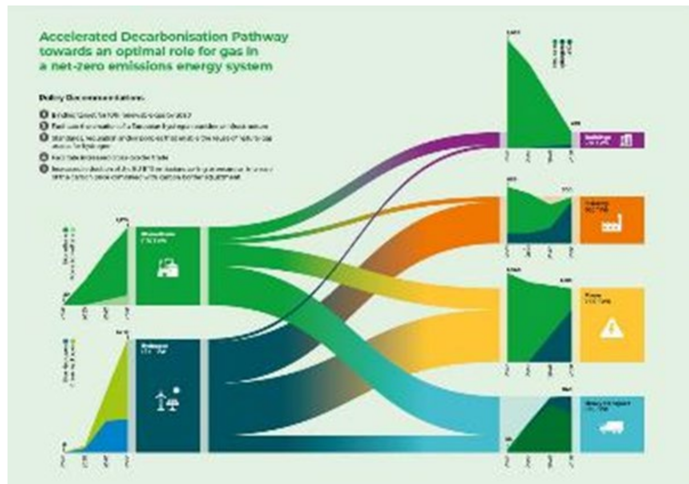
Gas for Climate 2050 – Pathway to a Net-Zero Emission Energy System – Policy strategies to decarbonize the energy system to meet climate change targets often focus on electricity and the value of gas and gas infrastructure is not equally appreciated. The (renewable) gas sector needs a consistent and credible vision on the future of gas and get policy endorsement to ensure a license to operate. Guidehouse supported the Gas for Climate consortium with scenario-analysis and vision development on the future role of gas alongside electricity.

Guidehouse estimated the potential for renewable gas using innovative approaches such as Biogasdoneright to avoid competition with food crops and to guarantee a GHG-emission reduction by 95% compared to 1990.

The system costs of two scenarios were compared: an electrification scenario and an electrification scenario with renewable gas. The renewable gas was distributed to sectors based on the largest marginal value of the gas.

Guidehouse provided recommendations regarding the design of the future energy system which is both sustainable and cost-efficient.

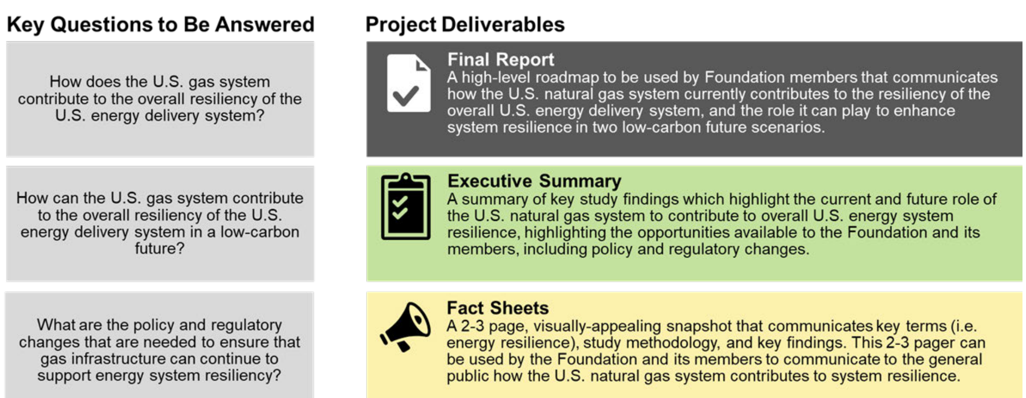
The Result: CEO statement supporting a target to achieve net zero greenhouse gas emissions by 2050. Two scenario modelling studies published in 2018 and 2019, compared optimized gas with a minimal gas 2050 scenarios. A pathway study 2020-2050 was published in 2020 and outlined several roads to achieve 2050 targets. 2030 Action Plan: A to-do list that was presented by the CEOs of Gas for Climate members to European Energy and Climate Commissioner Arias Cañete



European Pipeline Consortium: European Hydrogen Backbone. Guidehouse supported a consortium of 23 gas infrastructure companies across 21 countries to create a vision of a European Hydrogen Backbone – a dedicated hydrogen pipeline transport network spanning ten European countries. The Report "Extending the European Hydrogen Backbone" was released in April of 2021 and is an update to a report Guidehouse published in 2020. Guidehouse developed hydrogen infrastructure maps for 2030, 2035 and 2040. A copy of the report, which has successfully spurred the conversation around the role of hydrogen in the future European energy system, can be found at this link.

American Gas Foundation (AGF) – Energy System Resilience Whitepaper – Driven by the increasing frequency and severity of disruption events (i.e., extreme weather, cybersecurity), energy system resilience has arisen as a key priority in policy making discussions, particularly in discussions that aim to achieve decarbonization goals. The AGF wanted to understand the role that the U.S. natural gas system plays in contributing to overall energy system resilience today, and in a near-term decarbonized future.

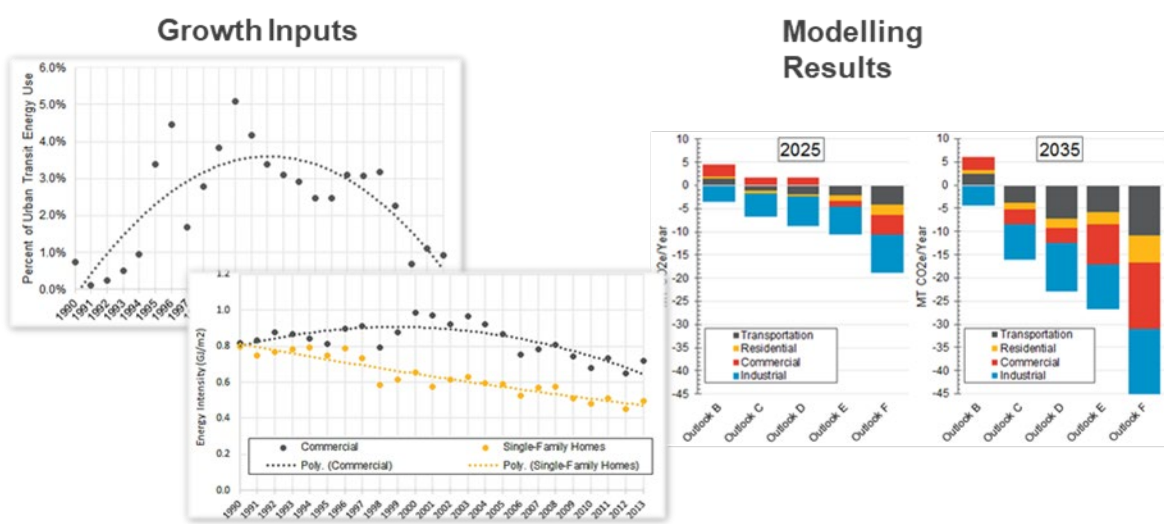
Guidehouse is working to define the current and near-term energy system states, including defining resilience and the characteristics on which it can be evaluated. Guidehouse is evaluating the state of the regulatory and policy landscape to provide recommendations of issues and policies that must be addressed to ensure resiliency in the energy system transformation.



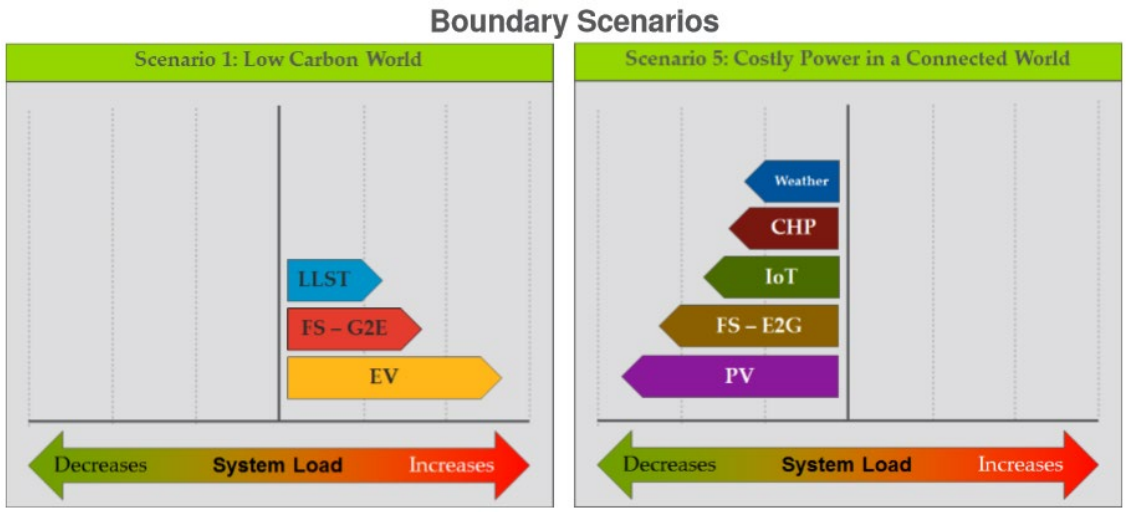
Guidehouse will provide clarity that gas infrastructure not only supports current energy system resilience, but also future energy system resilience. Guidehouse will also provide the Foundation with recommendations of issues/policies to be addressed to support the natural gas industry's role in a resilient future ES, along with a roadmap to be used by Foundation Members with external stakeholders to communicate how gas provides resiliency support today and in a decarbonized future.

A.3 Related Low Carbon, Scenario Analysis and Pathways Projects

Ontario MOE Fuels Technical Report & Decarbonization Analysis (2017) – Guidehouse supported the development of a technical report providing a comprehensive overview of the combustible fuels sector in Ontario since 2005, along with an examination of a set of outlooks to 2035 that capture opportunities for electrification of the economy and decarbonization of fuel supplies. Key input assumptions were developed in consultation with the IESO, and members of the Fuels Sector Working Group. These were applied to the CanESS integrated energy systems model to develop a set of possible future levels of fuels demand and combustion related GHG emissions. Under the most aggressive assumptions regarding electrification, incremental natural gas conservation and the adoption of alternative fuels (biofuels and less carbon intensive fossil fuels), the modelling predicted a 40% decrease in GHGs in 2035 compared to the Business As Usual (BAU). Following publication of the report, Guidehouse took part in a cross-province consultation process in support of the Ontario Long-Term Energy Plan, presenting a summary of the technical report's findings in 17 communities across Ontario.



Fortis BC Long Term Load Forecast Scenario Analysis (2016) - Guidehouse was engaged by FortisBC to develop a set of five future load scenarios to allow FortisBC to explore the implications for its long-term electric resource planning of significant structural shifts in load drivers. The study examined eight load drivers of interest: integrated photovoltaic storage systems (IPSS), electric vehicles (EVs), fuel switching (gas to electric and vice versa), climate change provoked weather shifts, large load sector transformation, the internet of things, and combined heat and power. Working closely with a large group of internal FortisBC stakeholders, Guidehouse built five projected scenarios designed to test the impact of possibilities that were "reasonable extremes", i.e., scenarios of combined uptake across load drivers that a qualitative risk assessment would indicate are in the long tails of the probability distribution, but still within the realm of the possible.

- 

Confidential Client Heat Pump Deep Dive (2020-2021). Given the impact of Heat Pumps on electric peak demand, Guidehouse supported a deeper dive analysis focused on refining results from an earlier analysis with real world performance data and greater variety in Heat Pump types. This analysis incorporated more robust and detailed information regarding electric, gas and dual fuel heat pump performance and how a deeper understanding of implementation in different parts of the clients' service territory would impact the scenarios' results. The team analyzed the thermal loads applied to and efficiency of heat pumps in different climate zones within the service territory and analyze differences in thermal loads by various housing structures. To characterize the heat pumps, Guidehouse developed the following:

- Summary of climate zones and customer segmentation and resultant use types detailing the number of customers in each segment and climate zone
- Heat Pump Performance Characteristics for each applicable combination of customer segments and climate zones and heat pumps (COP, annual and peak energy demand, capacity delivered at different temperatures)
- Daily load profiles for each combination of segment, climate zone and heat pump type that reflects a 1 in 2, a 1 in 10 and a 1 in 20-year cold day
- Total installed costs for each Heat Pump and customer type at different equipment sizing levels

The Heat Pump characterization was then incorporated into a broader GHG reduction modelling exercise to determine the impact on energy, peak and total costs.

Ontario Teachers' Pension Plan Low Carbon Economy Investment Framework – Guidehouse led one of the world's largest funds through a series of workshops to develop three principle analytic underpinnings, including carbon futures scenarios, economic performance indicators and a change management model. We developed a new strategic framework to transform the Fund's approach to identify opportunities in the shift to a low carbon economy and the catalysts and tipping points likely to result in positive carbon mitigation. Three core future scenarios highlighting the likely actions, economic and policy activity, technology innovation levels, consumer behaviour and capital flows in futures with differing carbon emission levels and climate change impacts. The assignment prioritized a large set of possible economic indicators of a shift towards a lower carbon economy, Navigant and the fund defined a short list of key KPIs offering insight on the scale, intensity, and pace of the shift.

Wien Energie City of Vienna Decarbonization Study (2017) – Guidehouse presented a decarbonization study for the City of Vienna (Austria) which was completed for Wien Energie, the local utility of Vienna. The concluding full-day program included multiple presentations to the Energie CEO, to Wien Energie employees, and a panel discussion in the evening with 120 participants and journalists. In the evening, the study was formally presented to Wien Energie's CEO. The study developed a decarbonization scenario for the city of Wien. It identified necessary measures in the sectors of power, heat, and transportation to reach these significant emission reductions, and provided a detailed view on the future composition of end-use energy in those sectors. It also estimated necessary investments and defined required regulatory framework conditions. Based on this study, we derived key business model options for Wien Energie to succeed in the transformation.

EHI, EU Pathways to a Decarbonized Building Sector (2016) - A scenario evaluation of the European residential heating sector by considering developments of low carbon technologies as well as current sales numbers in order to consider all relevant heating systems that will be available in the market by 2030. The scenario results are set in relation to the carbon dioxide emission targets of the EU "Roadmap for moving to a competitive low carbon economy in 2050.

BC Electric and Gas Conservation Potential (2017) - The group of electric and gas utilities in the province of British Columbia (BC Hydro, FortisBC Electric, FortisBC Gas, and Pacific Natural Gas [PNG]) engaged Guidehouse to prepare a dual-fuel (electric and gas) conservation potential review (CPR) and to quantify the technical, economic, and achievable energy efficiency potential for the entire province. For this province-wide assessment, Guidehouse used its proprietary and state-of-the-art DSMSim™ potential model. DSMSim is a bottom-up technology diffusion and stock-tracking model implemented using a System Dynamics framework and built on the Analytica software. Guidehouse customized its DSMSim model in order to model fuel-switching potential from multiple fuel types to electric and gas, and the adoption of alternative transportation fuels including electric vehicles. Guidehouse DRSim™ was also used to assess the Demand Response (DR) potential across the entire province.

Portfolio of the Future SoCalGas SDG&E (2016) - Faced with increasingly stringent goals for reducing future natural gas consumption, as well as the maturity of many traditional energy efficiency measures, SoCalGas needed assistance in accelerating the commercial acceptance of emerging energy efficient technologies. Guidehouse conducted an exhaustive search of emerging energy efficient natural gas technologies in the residential, commercial, and industrial sectors. We identified the most promising technologies and designed & implemented demonstrations, market tests, and market development efforts to accelerate the readiness of these technologies for inclusion in future utility energy efficiency programs. We conducted market development activities for 14 different technologies, many of which will now be included in SoCalGas' future programs. Based on the results of this effort, SoCalGas' sister company SDG&E asked Guidehouse conducted an exhaustive search of emerging energy efficient natural gas technologies in the residential, commercial, and industrial sectors. We identified the most promising technologies and designed & implemented demonstrations, market tests, and market development efforts to accelerate the readiness of these technologies for inclusion in future utility energy efficiency programs. We conducted market development activities for 14 different technologies, many of which will now be included in SoCalGas' future programs. Based on the results of this effort, SoCalGas' sister company SDG&E asked Guidehouse to complete a similar effort for their electric efficiency technologies.

City of Hamburg, Germany: Low Carbon Building Strategy (2017) - Guidehouse consulted for the City of Hamburg (Germany) in various projects related to the development a low carbon building stock (heating demand and heat supply). The following projects were implemented by Guidehouse:

- Support to foster networking and accelerate transformation process by showing how to achieve sustainable development
- GIS based inventory of the complete building stock of Hamburg providing information on relevant energy parameters
- Development of urban heat concepts for two districts in Hamburg
- Development of a detailed energy concept and scenario for a typical brick district in Hamburg

The following results were achieved as part of this project:

- GIS based tool to present the energy information of Hamburg's building stock
- Study in the context of the EU project "Transform" including social data to the technical information of buildings and heat supply
- Development of an energy and urban retrofitting concept on district level

Electric Vehicle Analysis and Modelling, Large Investor-Owned Utility (2017) - The client tasked Guidehouse with analysing the market penetration and impacts of the growth of electric vehicles in its service territory. The company requested that Guidehouse find the expected growth of electric vehicles across and within the service territory, when and where charging will occur, and the impacts of the expected charging. To complete the requested analysis, Guidehouse modelled projected electric vehicle penetration across the service territory at a zip code level and developed two penetration scenarios (base and alternative), analysed the charging locations and charging levels of existing infrastructure, and analysed the load profiles to determine system impacts (energy capacity) based on the charging location, time, and level. Guidehouse presented the results, via a dynamic web visualisation tool, to the client in the first quarter of 2018.

Enbridge Natural Gas Energy Efficiency Potential Study - Enbridge Gas Distribution retained Guidehouse to assess the technical, economic, and achievable potential for natural gas energy efficiency in its Ontario service territory. Guidehouse developed a base case forecast for natural gas sales and cost, savings, density, and other characterization data for approximately 90 efficiency measures. Guidehouse estimated the avoided downstream costs applicable to Enbridge's distribution territory to be used in conjunction with upstream avoided costs (commodity, storage, and transportation) for cost-effectiveness testing. Guidehouse developed forecasts of both technical and economic potential, by measure, disaggregated by sector, sub sector and end use by franchise strata. Guidehouse generated the overall benefit/cost ratio (TRC) for the forecasts and an economic potential forecast for six (6) achievable potential scenarios. To ensure stakeholder acceptance of the study results, workshops for each of the residential, commercial, and industrial sectors were held at various stages of the project.

Orange & Rockland, RNG Potential Analysis (2019-2020) - Orange & Rockland Utilities (O&R) was approached by large food processor who planned to connect an anaerobic digestor to O&R's gas network. O&R wanted to understand whether there was significant opportunity for RNG development in the region to support NYS' environmental goals. Guidehouse conducted a forecasting analysis to evaluate the RNG potential in O&R's service territory and surrounding region. Activities included:

- Collecting county-level data on feedstock availability for agricultural products, food/animal wastes, and other resources.
- Estimating RNG production potentials by feedstock, county, and region.
- Developing RNG production cost estimates and comparing these to forecasted gas prices
- Evaluating GHG emissions impacts by feedstock.
- Assessing current and future policies that support RNG development

The analysis provided O&R with a realistic projection for regional RNG potential considering local constraints and will support future planning activities and discussions with RNG developers. O&R submitted project findings as part of their rate case filing under PSC Proceeding 18-G-0068 (Link). RNG report can be downloaded here: Link

Electric Vehicle Analysis and Modelling, Large Investor-Owned Utility (2017) - The client tasked Guidehouse with analysing the market penetration and impacts of the growth of electric vehicles in its service territory. The company requested that Guidehouse find the expected growth of electric vehicles across and within the service territory, when and where charging will occur, and the impacts of the expected charging. To complete the requested analysis, Guidehouse modelled projected electric vehicle penetration across the service territory at a zip code level and developed two penetration scenarios (base and alternative), analysed the charging locations and charging levels of existing infrastructure, and analysed the load profiles to determine system impacts (energy capacity) based on the charging location, time, and level. Guidehouse presented the results, via a dynamic web visualisation tool, to the client in the first quarter of 2018.

Natural Resources Canada: Market Transformation Roadmap for Space Heating, Water Heating, and Window Products – Guidehouse was the technical advisor to Natural Resources Canada as it undertook a series of regular workshops with stakeholders of specific products in the space heating, water heating and windows markets to discuss R&D ad technology deployment barriers that must be overcome to move these markets towards greater energy performance. For each product category, NRCan invited stakeholders along the product supply chain, utility companies, other levels of government, etc., to participate in a series of workshops aimed at developing a roadmap for that product to guide government and industry energy efficiency activities over the next decade. Participants were organized into several working groups, each tasked with a specific product/technology. Working group discussions occurred in a series of workshops and covered topics including: setting R&D priorities, addressing barriers to market deployment, laying out the road map, and identifying key performance indicators to track progress.

European Heat Pump Association, Heat Pump Implementation Scenarios (2013) - We set up scenario calculations for different implementation paths of heat pumps until 2030, based on an analysis of current policies and possible future policy implementation supporting the use of heat pumps. The focus was on the key markets Germany, Sweden, Spain, France, Italy, The United Kingdom, Switzerland, and Austria. We investigated the application of heat pumps for space heating and domestic hot water purposes in residential buildings (differentiated by single- and multi-family buildings) and commercial buildings (such as offices, retail, and administration buildings) both for new buildings and retrofit situations.

Low Carbon Economy Strategic Framework for Confidential Pension Fund Client (2017) - Guidehouse supported a client in developing a new strategic framework for one of the world's largest pension plans to transform its approach identifying opportunities in the shift to a low carbon economy and the catalysts and tipping points likely to result in positive carbon mitigation. Guidehouse led the fund through a series of workshops to develop three principle analytic underpinnings, including carbon futures scenarios, economic performance indicators and a change management framework. Prioritizing a large set of possible economic indicators of a shift towards a lower carbon economy, Guidehouse and the fund defined a short list of key KPIs offering insight on the ***scale, intensity,*** and ***pace*** of the shift. Three core future scenarios highlighting the likely actions, economic and policy activity, technology innovation levels, consumer behaviour and capital flows in worlds with differing carbon emission levels and climate change impacts. Performance indicators frameworks monitoring detailed level activities in the economy across a range of catalyst areas. A new way of thinking about macro drivers of a shifting world economy and set of signals to explore for new investment opportunities and current portfolio risk.

Climate Change – Scenario Analysis Air Emissions Under the Canadian Regulatory Framework (2011) – A member of the Guidehouse team led a team employed by the CEA and its members, including all major generating utilities across Canada, to aggregate and analyze electricity sector futures outlooks. While managing the project and facilitating sessions aimed at developing an analysis and approach to lobby the federal government, the team was challenged to address a broad range of sensitivities affecting different power companies across the country. The project was taken on to develop a comprehensive database of current and forecasted electric generating fleet operations and inform the development of alternative approaches to regulating the sector in terms of GHGs and air pollutants. The analysis assessed the changes in compliance flexibility, fuel switching, new and emerging technology development and credit purchasing across a broad range of regulatory scenarios. The analysis investigated the opportunities and barriers for capital stock turnover, culminating in a lower emitting national power sector and the relevant and realistic timeframes in which this may be feasible.

Ontario Ministry of Energy Independent Review of Long-Term Demand Forecast - Guidehouse was retained by the Ministry to conduct a review of the Ontario Power Authority's long-term demand and energy forecast used as the basis for updating the Long-term Energy Plan. The objectives of the review was to assess the reasonableness of the forecast of Ontario gross (i.e. before conservation and demand management initiatives) and net (i.e. after conservation and demand management initiative) peak demand and energy consumption, identify critical assumptions, and establish whether critical assumptions are reasonable and consistent with broader trends.

City of Madison, Wisconsin: 100% Renewable Energy and Net Zero Strategy (2016) - The City of Madison, WI retained Guidehouse and local engineering partner Sustainable Engineering Group LLC to develop strategies and analysis to achieve their goal of 100% renewable energy and net-zero carbon for city operations and to continue their leadership role for the larger community. The approach included identifying demand and supply-side options for facilities, operations and fleet/transit, stakeholder engagement, development of model timelines and financial/environmental analysis for cost comparisons.

Appendix B. Guidehouse Overview

Guiding with Confidence. Navigating Futures Forward. Guidehouse is a leading global provider of consulting services to the public and commercial markets with broad capabilities in management, technology, and risk consulting. We help clients address their toughest challenges and navigate significant regulatory pressures with a focus on transformational change, business resiliency, and technology-driven innovation. Across a range of advisory, consulting, outsourcing, and digital services, we create scalable, innovative solutions that prepare our clients for future growth and success. Headquartered in McLean, VA., the company has more than 8,000 professionals in over 50 locations globally. Guidehouse is a Veritas Capital portfolio company, led by seasoned professionals with proven and diverse expertise in traditional and emerging technologies, markets, and agenda-setting issues driving national and global economies. For more information, please visit: www.guidehouse.com.

Guidehouse-at-a-Glance

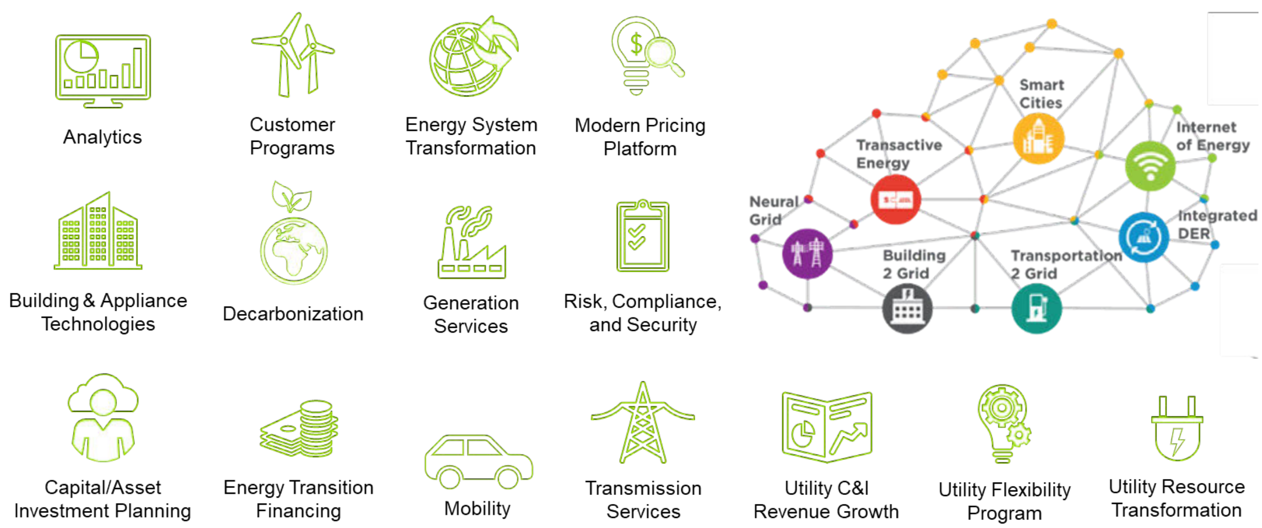
Energy, Sustainability, and Infrastructure. With over 700 consultants, our global Energy, Sustainability, and Infrastructure segment is the strongest in the industry. We are:

- A diverse, inclusive team of 700+ globally
- Go-to partner for leaders creating sustainable, resilient communities and infrastructure
- Trusted advisors to utilities and energy companies, large corporations, investors, NGOs, and the public sector

- Combining our passion, expertise, and industry relationships to forge a resilient path toward sustainability for our clients
- Enabling clients to reach their ambitions through transformation

- Turning vision into action by leading and de-risking the execution of big ideas and driving outcomes

Our Solutions Evolve Around the Energy Cloud. These solutions focus your most pressing needs to help you thrive in the rapidly changing environment.



Core Capabilities. Our core capabilities support our solution offerings and organized through Communities of Practice.

ENERGY

SUSTAINABILITY

INFRASTRUCTURE

- ✓ Market Research
- ✓ Organizational Transformation
- ✓ Carbon Pricing Design
- ✓ Customer Engagement Solutions
- ✓ Data Analytics & Modeling
- ✓ Design Thinking
- ✓ Energy Systems Modernization
- ✓ Enterprise Risk Management & Security
- ✓ Emerging Technology Program Support
- ✓ Generation Strategy & Advisory
- ✓ R&D Program Planning & Evaluation
- ✓ Corporate Climate Plan Advisory
- ✓ Policy & Regulation Advisory
- ✓ Utility Strategy Development
- ✓ Regulatory Support Services
- ✓ Renewables Integration
- ✓ Clean Energy Programs Design & Evaluation
- ✓ Procurement Strategy Planning
- ✓ Large-Scale Program Management
- ✓ Wholesale Market Analysis

Cody Wood

From: Decker Ringo <decker.ringo@guidehouse.com>
Sent: Thursday, December 16, 2021 3:43 PM
To: Cara-Lynne Wade; Cody Wood; Jennifer Murphy
Cc: Alvaro Lara; Andrea Roszell
Subject: [External] Enbridge-Guidehouse Scope of Work Extension

Importance: High

Hello Cara, Cody, and Jennifer,

Below is the description of an extension to our scope of work that Cara requested on our call today. Please let me know if you have any questions.

Enbridge requested that Guidehouse adjust the decarbonization scenarios and sensitivity cases under study in the Enbridge Decarbonization Study. The Enbridge team would like our report to include sufficient information to draw conclusions about the impacts of hybrid heating systems. Specifically, Enbridge wants to know how the adoption of hybrid heating systems would impact gas & electricity consumption, peak demand, and total costs. In an older version of results (Nov 15 version), Guidehouse modeled a demand forecast assuming very low adoptions of hybrid heating systems. For our most recent draft results (Nov 30 version), Guidehouse used a demand forecast that includes hybrid heating in 20% of homes in the Diversified scenario and 0% of homes in the Electric scenario. We understand the Pan-Canadian Framework's goal is for all heating equipment installed post-2035 to have heating efficiency greater than 100%. So, for the Electric and Diversified scenarios, Guidehouse will reallocate any homes with "low-carbon gas furnace" heating equipment post-2035 to gas HPs or to hybrid heating systems. Guidehouse will consider product lifetimes and natural replace-on-failure turnover when modeling the hybrid heating adoption curve.

We expect that Enbridge will want the report to investigate and report on the value of hybrid systems in terms of their peak reduction and cost benefits. Our team recommends that we pursue this by comparing a case with low/minimal HH adoption to a case with high adoption of hybrid heating.

Our team proposes the following steps to update the Enbridge Decarbonization Pathways analysis:

1. Revert the Diversified pathway back to a no-hybrid-heating assumption to match the ETSA demand forecast. This provides an apples-to-apples comparison with the Electric pathway, since the Electric pathway does not include HH. To comply with Pan-Canadian goals, any gas-powered heating systems installed post-2035 will be changed to gas heat pumps.
2. Model a fourth sensitivity case to examine the impacts of adopting hybrid heating, where ***X*** percent of homes are equipped with hybrid heating. For a standard single-family residence, a hybrid heating system comprises a high efficiency gas furnace and a moderate-capacity (e.g., 3 tons) moderate efficiency (e.g., 16 SEER) electric heat pump. This will help Enbridge to understand the impact of the "first X percent of hybrid heating," which could be useful for justifying hybrid heating investments.
3. Revise the near-final draft report (work in progress) to revert the Diversified demand forecast and to revert sensitivity cases 1 to 3 back to a no-hybrid-heating baseline.
4. Add the new sensitivity case #4 for hybrid heating to the report, and update the report's discussion and results accordingly.

Following this approach, the revised final report would have the following outputs:

- Demand, consumption, emissions, and cost forecast for Electric pathway (unchanged)
- Demand, consumption, emissions, and cost forecast for Diversified pathway (reverted to an assumption of no hybrid heating)
- 4 sensitivities for each of these two pathways. For the first 3 sensitivities, the only change is that base-case Diversified pathway is reverted to no hybrid heating. The fourth sensitivity is new.
    - Sens 1: End use costs for distributed generation equipment (e.g., rooftop solar and home batteries) decrease faster than forecast. (Expected outcome: Cost of Electric scenario decreases, but Electric scenario is still much more expensive than Diversified scenario)
    - Sens 2: Limit investment in gas projects so that total energy system spending is less than the total Energy System Costs projected for the Diversified scenario. (Expected outcome: Net-zero target is not met)
    - Sens 3: Costs of hydrogen infrastructure costs less than forecast. (Expected outcome: The total Energy System Cost decreases for both scenarios, maybe the cost gap between scenarios gets a bit smaller.)
    - Sens 4: Hybrid heating deployed in Ontario along a projected adoption curve suggested by Enbridge. (Expected outcome: end user costs and electric system costs are lower for hybrid heating case.)

Deliverables:
Guidehouse will deliver a revised draft final report that incorporates these changes by January 31, 2022. Guidehouse will invite an additional round of revisions from Enbridge, with comments requested by February 11, 2022. Guidehouse will deliver a revised final report on February 18, 2022.

Budget:
The work described above involves effort beyond the original scope of our Guidehouse's contract with Enbridge. The cost of this additional scope is [redacted]

Thanks,

J. DECKER RINGO | Associate Director
Energy, Sustainabilty & Infrastructure | Guidehouse
1200 19th St. NW | Suite 700 | Washington DC 20036 | USA
202.973.3170 Direct | decker.ringo@guidehouse.com
guidehouse.com

Cody Wood

From:	Decker Ringo <decker.ringo@guidehouse.com>
Sent:	Wednesday, March 9, 2022 2:08 PM
To:	Cody Wood; Jennifer Murphy
Subject:	[External] Enbridge-Guidehouse Scope of Work Extension #2
Importance:	High

Hello Cody and Jennifer,

Below is the description of an extension to our scope of work that you requested on our call Monday. Please let me know if you have any questions.

Enbridge requested that Guidehouse adjust the decarbonization scenarios and sensitivity cases under study in the Enbridge Decarbonization Study. The Enbridge team would like our analysis and report to include assumptions regarding significant uptake of geothermal heating systems. Specifically, Enbridge wants include the adoption of geothermal heating systems in the Diversified and Electrified scenarios, and include assumptions about geothermal systems in projections of gas & electricity consumption, peak demand, and total costs. Prior versions of the pathways analysis used energy demand forecasts based on Enbridge's ETSA study, which assumed minimal adoption of geothermal heat pumps. We understand that Enbridge is considering new opportunities in the geothermal space and would like to model a low-carbon future that assumes a significant role for geothermal energy systems.

Our team proposes the following steps to update the Enbridge Decarbonization Pathways analysis to include geothermal technologies.

1. With EGI input, define the types of geothermal systems to be included in the revised analysis (e.g., single-building scale, neighborhood-scale, and/or utility scale geothermal)
2. With EGI input develop reasonable assumptions regarding the potential uptake of geothermal heating over time through 2050.
3. Adjust the ETSA demand forecast used as the starting point for this analysis to include assumptions regarding geothermal uptake.
4. Locate and input a load shape profile for geothermal heating systems in northern climates, reflecting that due to their efficiency, individual geothermal systems will typically result in lower peak load growth compared to conventional air-source heat pumps.
5. Locate and input assumptions regarding end user costs for geothermal heating equipment installation.
6. Re-run Low Carbon Pathways model to model two scenarios and four sensitivities (as defined previously in 17 Feb 2022 draft report version)
7. Re-populate figures and tables in the draft report. Revise report language to reflect updated results.
8. Add discussion of geothermal technologies and assumptions to the report.

Following this approach, the revised final report would have charts and formats similar to the 17 Feb 2022 draft report version, but would include enhanced assumptions and discussion regarding geothermal technologies.

Guidehouse also sees this model update as an opportunity to incorporate supply-side assumptions around nuclear small modular reactors (SMRs), a topic on which Enbridge recently expressed interest. If requested by Enbridge, Guidehouse will update supply-side modeling assumptions to add nuclear SMR as an available technology for the capacity expansion modeling, and add discussion of SMRs to the revised report.

Deliverables:
Guidehouse will deliver a **revised draft final report** that incorporates these changes by **April 6, 2022.** Guidehouse will invite an additional round of revisions from Enbridge, with **comments requested by April 15, 2022**. Guidehouse then will deliver a revised final report on **April 22, 2022**.

Budget:
The work described above involves effort beyond the original scope of our Guidehouse's contract with Enbridge. [redacted]

Thanks,

J. DECKER RINGO | Associate Director
Energy, Sustainabilty & Infrastructure | Guidehouse
1200 19th St. NW | Suite 700 | Washington DC 20036 | USA
202.973.3170 Direct | decker.ringo@guidehouse.com
guidehouse.com

POSTERITY GROUP

High-Level Cost Estimate for Creating a New Scenario based on the Diversified Portfolio Scenario

Project: Energy Transition Scenario Analysis (ETSA)
Re: Estimated cost range to create a new scenario by adjusting some Critical Drivers in the Diversified Portfolio scenario
Submitted to: Jennifer Murphy, Enbridge
Submitted by: Alex Tiessen & Erika Aruja, Posterity Group
Version: 1
Date Submitted: 10 June 2021

This memo provides a rough estimate of the cost to develop a new scenario for EGI based on revising some settings for select Critical Drivers currently used in the Diversified Portfolio scenario to achieve deeper GHG reductions. Depending on the Critical Drivers adjusted and the number of rounds of revisions, we expect the cost to range between [redacted] The cost estimate reflects a lower and upper range and can be revised to be more precise when more details of the scope of work become available.

The Task

- Create a new scenario that achieves further GHG reductions beyond what the Diversified Portfolio scenario is currenting forecasting by adjusting some Critical Driver settings.
- This will likely be by adjusting Critical Drivers that EGI can control: RNG, hydrogen, CCS and DSM budget.

Assumptions:

- The new scenario will be created using the Critical Drivers established for the ETSA project; no new Critical Drivers will be developed.
- The current models will be used (i.e., model structure is maintained)

Table 1 – Additional Scenario Scoping Assumptions

Activity	Narrower Scope/Lower Level of Effort Description	Broader Scope/High Level of Effort Description
Identify which Critical Drivers should be adjusted	• EGI defines which Drivers should be adjusted and discusses with PG. • Drivers adjusted do not require additional research and analysis from PG to develop inputs such as RNG, H2, NGT, CCS and DSM budget.	• EGI and PG work collaboratively to define which Drivers should be adjusted. • Drivers adjusted require additional research and analysis from PG to develop inputs such as C&S, non-price driven fuel switching, and climate change.
Develop & define settings for the Critical Drivers that deviate from the current settings	• EGI provides setting values for Drivers and they are in the same format as previous inputs. • PG reviews and intakes new data.	• PG conducts research and analysis to develop inputs/settings for Drivers. Or, • EGI provides settings for Drivers in a different format than previous inputs. PG reviews and processes data to use in the model.
Model the new scenario	• PG constructs a new scenario and runs the model. • A DSM budget-solver model run is not required.	• PG constructs a new scenario and runs the model. • A DSM budget-solver model run is required.
Review the results and revise if necessary	• PG and EGI review results • Minimal or no revisions are required.	• PG and EGI review results • Major revisions are required.
Documentation of the scenario inputs and results	• PG writes concise memo to document inputs and results	• PG writes small report explaining the scenario, the process to develop inputs, details the inputs and discusses the results in comparison to the other scenarios.
Update the PowerBI data visualization dashboard.	• Update the PowerBI data visualization dashboard with the new scenario using the existing format.	• Update the PowerBI data visualization platform with the new scenario.

Activity	Narrower Scope/Lower Level of Effort Description	Broader Scope/High Level of Effort Description
		• Add additional exhibits not previously included in the dashboard.
Project Management	• On-going communication, budget updates, meetings, etc.	• On-going communication, budget updates, meetings, etc.
Cost Estimate	[redacted]	[redacted]

Alternative Approaches:

- GHG target goal seeking: If EGI wants to reach a GHG reduction target in a specific year, PG can see what volumes of RNG and H2 would be required to meet that target. This would likely be an iterative process where multiple model runs are conducted until the GHG target is reached.
  - We could also explore various combinations of RNG and H2 required to meet the target.

POSTERITY GROUP

ETSA Planning Scenario Updates Proposal

Project: Energy Transition Scenario Analysis
Re: Updating the RNG forecast used in the Planning scenario
Submitted to: Enbridge Gas
Date Submitted: June 29, 2022
Version: 1

This proposal provides an estimated level of effort and elapsed time required to update the RNG forecast and name for the Planning scenario, and reflect the updates in the data visualization platform and report.

1 Scope of Work

Posterity Group (PG) understand the following tasks are required:

- Revise the RNG forecast in the Planning scenario model using the newest RNG forecast provided by Enbridge Gas. This task will require PG to rerun the sector-models to achieve the new RNG targets and then rerun the DSM module as the new RNG volume will affect DSM savings.
- Revise the name of the Planning scenario
- Update the data visualization platform with the new model output and scenario name
- Update the scenario report

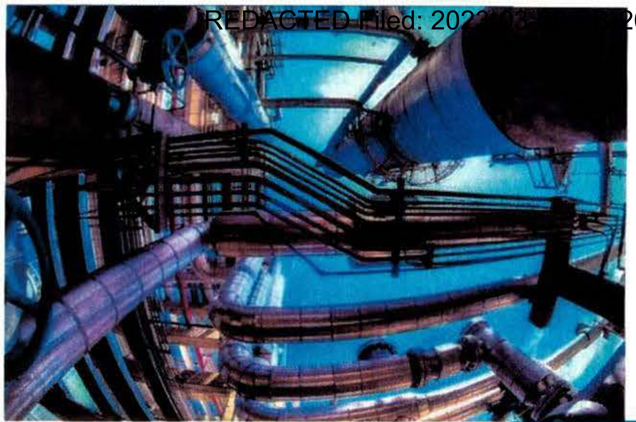
2 Level of Effort, Budget & Invoicing

The table below shows the estimated number of hours per task. W[redacted] We propose to employ a "time and expense to a cap" structure with invoicing monthly. Enbridge Gas can contract through the PO previously established for the ETSA project if that is most convenient.

[redacted]

3 Timeline

PG expects it will take four to six weeks to complete the work upon receiving the new RNG forecast and revised scenario name from Enbridge Gas.



Proposal to Assess the Future Utilization for the Dawn Parkway System

October 26, 2021

Submitted to: Max Hagerman
Enbridge Gas Inc.

Submitted by:
ICF Resources, LLC
9300 Lee Hwy
Fairfax, VA 22031

ICF

Mr. Max Hagerman
Enbridge Gas Inc.

RE: Assessment of Future Utilization for Dawn Parkway System

Dear Max:

ICF is pleased to offer to Enbridge Gas, Inc. this proposal to provide an assessment of future utilization for Dawn Parkway System.

Enbridge currently has contracts on Dawn Parkway System and wants to assess the market to understand the risk of de-contracting on the Dawn Parkway system in the future. ICF understands that the assessment will be used by Enbridge to evaluate the future utilization of Dawn Parkway system for the next rebasing term (2024-2028) and slightly beyond (until 2034). This study will be used to understand the risk of turnback on the system over that timeframe. The study will focus on examining the current contracts and looking at the supply and demand balance to forecast the utilization of Dawn Parkway system until 2034. The study will be based on the most recent ICF gas market base case outlook. The results of the study will be documented in a short memo/report suitable for filing with the OEB. ICF will provide this study for the [redacted].

ICF will also provide oral testimony on behalf of Enbridge as an independent consultant before the OEB, as well as other regulatory support as requested. The oral testimony and other regulatory support will be provided on a Time & Materials (T&M) basis. As Subject Matter Experts, [redacted]

ICF proposes to complete the work based on the terms and conditions specified in the existing contract between ICF and Enbridge dated June 15, 2020. To authorize this work, please sign the authorization and e-mail a PDF of the signed authorization to Michael.sloan@icf.com.

If you have any questions, please call me at 703-403-7569.

We look forward to the opportunity to work with you on this assignment.

Sincerely,

Michael Sloan

Managing Director, Natural Gas and Liquids Advisory Services

Authorization to Proceed

I hereby authorize ICF to proceed according to the scope of work described in this proposal under the terms and conditions in the contract between ICF and Enbridge dated June 15, 2020.

Accepted for: **Enbridge**	*Accepted for:* **ICF Resources, LLC**
Signed: Mat Hagerman	*Signed:* Joseph S McGrath
Name (printed): MAT HAGERMAN	*Name (printed):* JS McGrath
Title: MGR, CAPACITY MANAGEMENT	*Title:* Sr Dir Contracts
Date: Nov. 22/2021.	*Date:* Nov 22 2021

ENBRIDGE

Statement of Work

PSA Number (A)	32090	Enbridge BU Number (B)	
SOW Project Name (C)	Finance Advisory Services	SOW Project Number (D)	
Contract Number	[Enter as (A)-(B)-(C)-(D)]		

Enbridge	**Enbridge Gas Inc.**, a company incorporated in Toronto having its registered office at 500 Consumers Rd, Toronto ON M2J 1P8 ("**Enbridge**"); and
Service Provider	**Ernst and Young**, a company incorporated in Toronto having its registered office at One London Place, Suite 1800, 255 Queens Ave., P.O. Box 5332, London ON N6A 5S7 (the "**Service Provider**").
Commencement Date	February 1, 2019
Completion Date	January 31, 2020

THIS STATEMENT OF WORK ("SOW") IS ENTERED INTO BETWEEN ENBRIDGE AND SERVICE PROVIDER AS OF THE COMMENCEMENT DATE, AND IS SUBJECT TO THE PROFESSIONAL SERVICES AGREEMENT BETWEEN ENBRIDGE AND THE SERVICE PROVIDER DATED 1 NOVEMBER 2018 (THE "PSA"). ANY CAPITALIZED TERM USED IN THIS SOW BUT NOT DEFINED SHALL THE MEANING ASCRIBED TO SUCH CAPITALIZED TERM IN THE PSA

The Service Provider will provide Services to Enbridge on the terms set out below:

1) Description of Work

The Service Provider shall provide to Enbridge the following:

In support of the amalgamation between Enbridge Gas Distribution (EGD) and Union Gas (UG) to create Enbridge Gas Inc. (EGI), we understand you would like assistance as finance alignment activities continue to progress. Some examples of activities that can be provided include, but are not limited to:

- Process Improvement
  - Identifying business requirements and efficiencies as it relates to processes, systems, reports etc.
  - Identifying risks and mitigation strategies
- Documentation
  - Conduct or facilitate discussions (as required) to document aligned EGI processes
  - Creation/update and management of process related documentation for the EGI Finance department as required.

ENBRIDGE

Statement of Work

PSA Number (A)	32090	Enbridge BU Number (B)	
SOW Project Name (C)	Finance Advisory Services	SOW Project Number (D)	
Contract Number	[Enter as (A)-(B)-(C)-(D)]		

- Project Management
  - o Assist with management of execution work streams as required.
  - o Project management over finance initiatives as required.
- Third Party Studies
  - o Prepare and conduct third party studies for the purpose of gathering benchmarking information to support Enbridge's OEB driven processes.
  - o Pull together external and internal data sources to obtain required study results.
  - o Respond to interrogatories and undertakings. Appear as a witness in proceedings as required.
- Provide assistance with day to day responsibilities to facilitate the participation of EGI Finance team members in amalgamation activities
- Provide subject matter resources to support project(s) as required
- Other work as identified by Enbridge Finance management

2) SOW Representatives

Each Party shall appoint a Representative in this SOW who shall be available on a dedicated basis and act as the single point of contact for the other Party, and who will be responsible for co-coordinating, overseeing and ensuring the timely performance by such Party's obligations under this PSA.

	Enbridge	Service Provider
Name	Tanya Ferguson	Andrew Grainger
Address	500 Consumers Rd.	One London Place, Suite 1800, 255 Queens Ave, PO Box 5332
City	Toronto	London
State / Province	Ontario	Ontario
Phone	416 495 5754	519 646 5567
Email	tanya.ferguson@enbridge.com	Andrew.Grainger@ca.ey.com
Fax		

3) Location of Work

The Work shall be provided by the Service Provider at the following location(s):

- Enbridge Gas Distribution, 500 Consumers Rd., North York, Ontario
- Union Gas, 50 Keil Dr N., Chatham, Ontario

4) SOW Project Schedule

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Contract Number	[Enter as (A)-(B)-(C)-(D)]

The Service Provider shall ensure that Service Provider's Key Personnel adhere to the following Project schedule and Project Milestone Dates

This scope of work will span a 12-month period and will consistent of multiple smaller projects. Prior to the onset of a new project covered by this SOW, a detailed project schedule and estimate of fees will be created and agreed upon between Enbridge and the Service Provider.

5) Key Personnel

The Service Provider agrees that the following Key Personnel of Service Provider shall be dedicated to the performance of the Services under this SOW:

Key Personnel	Title
Andrew Grainger	Partner

Andrew will work with Enbridge Finance management for each individual assignment to determine the additional resources to be used, dependent on the specific scope of work agreed upon.

6) Permitted Subcontractor

This section is not applicable as no subcontractor will be utilized.

7) Currency

Payments for this SOW will be in CAD.

8) Staffing Model and Rates

Based on the agreed upon scope of work, the services outlined in this SOW will cover the period beginning on February 1, 2019 and ending on January 31, 2020. The fees are estimated to be approximately [redacted] Though a range of fees for the services has been provided, the amount for the services may be less if the projected level of effort is not as high as expected or if EGI decides to decrease the scope of the project. If, during the term of this Agreement, the Service Provider determines that the fee estimate will be significantly exceeded they will promptly contact Enbridge to discuss any adjustments to the scope of our work or our fees.

ENBRIDGE

Statement of Work

PSA Number (A)	32090	Enbridge BU Number (B)	
SOW Project Name (C)	Finance Advisory Services	SOW Project Number (D)	
Contract Number	[Enter as (A)-(B)-(C)-(D)]		

The estimated fees is based on the following rate card that is outlined in the Professional Services Agreement dated November 1, 2018 :

Role	Location	Unit Rate ($/Hr.)
Partner	Toronto	[redacted]
Senior Manager	Toronto	
Manager	Toronto	
Senior	Toronto	

9) Travel, Hospitability and Other Pass Through Expenses

Enbridge will only pay or reimburse Service Provider for pre-approved Travel, Hospitability and Other Pass Through Expenses ("Expenses") as listed below:

- All reasonable out-of-pocket expenses for items such as travel, meals, accommodation and other matters specifically related to your engagement will be invoiced at their cost, consistent with Enbridge travel and expense policies. Pre-approval will be sought for any travel beyond the contemplated to-and-from the Chatham, Ontario and North York worksites.

Unless otherwise set out in this Statement of Work or in a Change Order, Pass Through Expenses may not exceed:

i) 10% of professional fees

10) Invoicing Instructions

In order to support prompt payment please reference the following when submitting all invoices related to this SOW ensure all invoices contain the following information:

- Enbridge Gas Inc. purchase order number created to support this SOW
- GST Number;
- GST amounts identified as a separate line item;
- All taxes identified as separate line items (or clearly indicate how included); and
- Correct Service Provider corporate name (including numbered companies).

ENBRIDGE

Statement of Work

PSA Number (A)	32090	Enbridge BU Number (B)	
SOW Project Name (C)	Finance Advisory Services	SOW Project Number (D)	
Contract Number	[Enter as (A)-(B)-(C)-(D)]		

- A line item breakdown of total expenses for each of the Finance initiatives being managed for the invoicing period under this SOW.

All supporting documentation associated with the invoice including, but not limited to:

- Alignment of resource hours for work streams within each Finance initiative that shows up as a line item on the invoice.
- Detailed back-up provided for all cost reimbursable expenses in accordance with the Agreement; and
- Other required documents as may be specific to the SOW or an Enbridge Representative.

All invoices must be billed to:

Enbridge Gas Inc.

Attention: Accounts Payable

50 Keil Drive North, Chatham ON N7M 5M1

Alternatively, the Contractor may submit its invoices relating to this Work Order via e-mail to apcaeastinvoices@uniongas.com.

11) Special Conditions to this SOW

The Parties have agreed to the following Special Conditions, which are permitted modifications and/or supplements to the terms of the Statement of Work:

a) Limitations on Scope

EY will not identify, address or correct any errors or defects in Enbridge's computer systems, other devices or components thereof ("Systems"), whether or not due to imprecise or ambiguous entry, storage, interpretation, processing or reporting of data. EY will not be

ENBRIDGE

Statement of Work

PSA Number (A)	32090	Enbridge BU Number (B)	
SOW Project Name (C)	Finance Advisory Services	SOW Project Number (D)	
Contract Number	[Enter as (A)-(B)-(C)-(D)]		

responsible for any defect or problem arising out of or related to data processing in any Systems.

b) Enbridge's Specific Obligations

Enbridge will not, and will not permit others to, quote or refer to the Reports, any portion, summary or abstract thereof, or to EY or any other EY Firm, in any document filed or distributed in connection with (i) a purchase or sale of securities to which the United States or state securities laws ("Securities Laws") are applicable, or (ii) periodic reporting obligations under Securities Laws. You will not contend that any provisions of Securities Laws could invalidate any provision of this Agreement.

Enbridge shall assign a qualified person to oversee the Services. Enbridge is responsible for all management decisions relating to the Services, the use or implementation of the output of the Services and for determining whether the Services are appropriate for your purposes.

c) Special Additional Terms and Conditions

The Services are advisory in nature. EY will not render an assurance report or opinion under the Agreement, nor will the Services constitute an audit, review, examination, or other form of attestation as those terms are defined by the American Institute of Certified Public Accountants. None of the Services or any Reports will constitute any legal opinion or advice. EY will not conduct a review to detect fraud or illegal acts.

Notwithstanding anything to the contrary in the Agreement or this SOW, EY does not assume any responsibility for any third-party products, programs or services, their performance or compliance with your specifications or otherwise.

EY will base any comments or recommendations as to the functional or technical capabilities of any products in use or being considered by Enbridge solely on information provided by Enbridge's vendors, directly or through Enbridge. EY is not responsible for the completeness or accuracy of any such information or for confirming any of it.

ENBRIDGE

Statement of Work

PSA Number (A)	32090	Enbridge BU Number (B)	
SOW Project Name (C)	Finance Advisory Services	SOW Project Number (D)	
Contract Number	[Enter as (A)-(B)-(C)-(D)]		

This Statement of Work, the General Terms, its Attachments and any other documents referred to in the Statement of Work constitute the entire agreement between the Parties with respect to the subject matter of the Statement of Work and (to the extent permissible by law) supersedes all prior representations or oral or written agreements between the Parties with respect to that subject matter, provided that neither Party is attempting to exclude any liability for fraudulent misrepresentations. No conflicting or additional terms or conditions endorsed on, delivered with or contained in any Service Provider quotation, acknowledgement of order, delivery note, invoice or other Service Provider document shall form part of the Statement of Work and all such conflicting or additional terms are hereby rejected by the Enbridge. The Statement of Work may be entered into in any number of counterparts.

Enbridge Gas Distribution, Inc.

Per: Wendy Zelond

Name: Wendy Zelond

Title: Vice President Finance

Ernst & Young LLP

Per: Andy Grainger

Name: Andrew Grainger

Title: Partner*

**Andrew Grainger is an incorporated limited partner of Ernst & Young LP that provides services to Ernst & Young LLP*

Ernst & Young LLP
Ernst & Young Tower
100 Adelaide Street West, P.O. Box 1
Toronto, Ontario M5H 0B3

Tel: 416 864 1234
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ey.com/ca

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Ms. Wendie Brodie Lumley
Enbridge Gas Inc.
500 Consumers Rd
North York, Ontario
M2J 1P8

30 May 2019

Dear Wendie:

Re: Scope Expansion – Finance Advisory Services Statement of Work

As you know, Enbridge Gas Inc. ("you" or the "Client") engaged the Canadian firm of Ernst & Young LLP ("EY" or "we") to provide certain Finance Advisory Services pursuant to the Finance Advisory Services Statement of Work (the "SOW") commencing February 1, 2019.

This letter is to confirm our agreement to expand the scope of EY's engagement to include additional services. Specifically, the following services are being added to the scope of the SOW:

> Under this Scope Expansion, we will provide accounting and financial reporting assistance in connection with Enbridge Gas Inc.'s review of overhead capitalization rates and provide observations and recommendations to management as a result of our procedures performed (these services are referred to as the "Accounting Services").
>
> At your direction, we will:
>
> - Interview Enbridge Gas Distribution Inc. and Union Gas Inc. employees to better understand the nature of costs incurred and their respective drivers
> - Discuss historical costs incurred and existing capitalization approaches
> - Evaluate the nature of costs incurred, cost drivers and existing overhead rates against benchmark data to provide our observations and recommendations regarding the overhead rate and capitalization approach; and
> - Based on information gathered, recommend amendments, as necessary:
>   - To your existing regulatory and accounting policies;
>   - To your existing overhead capitalization approach; and
>   - To your existing business processes related to the capitalization of overhead.
> - Assist Regulatory in identifying changes which may impact the OEB mandated deferral account
> - Assist you in the design of internal controls in response to changes in the new approach
>
> We will provide you with the following written Report:

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- A report detailing the procedures performed, the results of the benchmarking analysis, observations related to your existing overhead capitalization approach and capitalization rates and comments on your accounting and regulatory policy for overhead capitalization.

Our Report is meant to assist management in its conclusion regarding a reasonable overhead capitalization rate for the purposes of Enbridge Gas Inc.'s future regulatory filings.

Upon request, EY may act as an expert witness in a regulatory hearing regarding Enbridge Gas Inc.'s capitalization of overhead as it pertains to the results of the procedures performed under this SOW. We understand that as a witness, we may be asked to participate in the stakeholder engagement and hearing process, which may include:

- Presentation of the results of the review to stakeholders
- Preparation of a written report to be filed with the Ontario Energy Board ("OEB")
- Responding to interrogatories and undertakings
- Appearing as a witness in future regulatory proceedings

We may engage in discussions with your personnel, including officers and employees, and outside consultants, as determined by you. We may also read documentation, including contracts and memoranda, as specified by you. Further, we may identify factors or considerations that are relevant to your analysis of identified accounting and financial reporting matters.

We may assist you in interpreting the relevant accounting and reporting literature based on your general circumstances, and provide our views on those factors (including your characteristics and structure) which may influence the choice of your accounting policy. We will not conclude on the appropriate accounting treatment based on specific facts or recommend which accounting policy/treatment you should select/adopt. Any observations we provide are intended to assist you as you reach, document and implement your own conclusions and will not constitute our concurrence with, or support of, your proposed accounting or reporting.

We may provide certain observations as to our understanding of the views of your independent auditor or the staff of the Ontario Securities Commission, Securities and Exchange Commission, or the Ontario Energy Board. We may provide such observations without having any prior discussion with your independent auditor or the staff of the Ontario Securities Commission, Securities and Exchange Commission, or the Ontario Energy Board and accordingly, their actual views on a particular topic or issue may differ.

We may, upon your written request, assist you in documenting the conclusions you have reached or positions you have taken on accounting and reporting matters, including the accounting policies you select.

You will be responsible for implementing and further customizing these Reports, and for your use thereof and their effectiveness. We will have no obligation with respect thereto.

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We will not test, verify or otherwise confirm the accuracy and completeness of any information, statements or data that is provided to us by you or on your behalf, including information provided by your advisors, customers or vendors.

You alone are responsible for any decisions to implement actions identified in the Services, including as necessary to apply US Generally Accepted Accounting Principles ("US GAAP") appropriately and for compliance with applicable regulatory requirements, including the determination of your accounting policies. You are solely responsible for the preparation of your financial statements, including making all of the judgments inherent in preparing them.

You are responsible for notifying your independent auditor of the performance of the Accounting Services and consulting with them on the application of accounting principles and your related accounting policies. You agree that we may make inquiries of your independent auditor in connection with the performance of the Accounting Services.

EY will not render an assurance report or opinion under the Agreement, nor will the Services constitute an audit, review, examination, or other form of attestation, as those terms are defined by Chartered Professional Accountants of Canada ("CPA Canada"), the American Institute of Certified Public Accountants ("AICPA") or the Public Company Accounting Oversight Board. Accordingly, we will not express any form of assurance on accounting matters, financial statements, any financial or other information or internal controls as part of the Services.

We will not provide a professional opinion on the application of accounting principles pursuant to CPA Canada's standards for Reports on the Application of Accounting Principles (as set out in section 7600 of the CPA Canada Handbook) (as amended and interpreted) or pursuant to analogous AICPA standards. None of the Services or any Reports will constitute any legal opinion or legal advice. We will not conduct a review to detect fraud or illegal acts.

Any observations or comments with respect to your internal control matters will provide no assurance with respect to their effectiveness or their compliance with applicable laws and regulations. You alone are responsible for establishing and maintaining adequate internal control over financial reporting and the Services do not replace your responsibility for establishing the effectiveness of internal controls. In addition, you may not rely on us to draw to your attention matters that may be relevant as to whether or not your system of internal control is effective.

These changes are effective as of May 30, 2019. With the exception of these changes, the SOW remains in full force and effect and governs all services provided pursuant to the SOW. This letter shall be governed by and construed in accordance with the laws of the Province of Ontario.

EY
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To confirm your agreement, please sign a copy of this letter where indicated below and return to Fred Clifford, Fred.E.Clifford@ca.ey.com. If you have any questions concerning these changes or the terms of our engagement, please contact Fred Clifford or Abbas Lakha, Abbas.Lakha@ca.ey.com.

Very truly yours,

Ernst + Young LLP

Chartered Professional Accountants
Licensed Public Accountants

per Fred Clifford

Agreed:

Enbridge Gas Inc.

by____________________________
Name: Wendie Brodie Lumley
Title: Director, Business Support

ENBRIDGE

500 Consumers Rd
North York ON M2J 1P8

Hulya Sayyan, Senior Advisor Demand Forecasting & Analysis
Tel: 416-495-6332
Email: hulya.sayyan@enbridge.com

January 28, 2021

GUIDEHOUSE CANADA LTD.
100 King Street West, Suite 4950
Toronto Ontario M5X 1B1

Dear Sir / Madam,

RE: Consulting Agreement with Enbridge Gas Inc.

Attached please find for signature our Consulting Agreement. Kindly arrange to have the Agreement and the attached Schedule signed. Please ensure you read and understand all of the terms and conditions of the Agreement, as well as the enclosed Statement on Business Conduct and Lifesaving Rules.

We will also require the following:

- A current clearance certificate or letter of exemption from the Ontario Workplace Safety and Insurance Board ("WSIB"). If your employees are in a jurisdiction other than Ontario, please provide equivalent proof of coverage, and new proof of coverage must be filed with us upon expiry/renewal of such proof of coverage.

Please return the applicable WSIB document noted above, together with a signed copy of the Consulting Agreement and a signed copy of the Schedule, promptly following receipt of this letter. Upon receipt of all the documents in our office, we will execute the Agreement and a PDF copy of the Agreement will be returned to you for your records.

If you have any questions, please contact me at the above-noted telephone number.

Sincerely,

Hulya Sayyan
Senior Advisor Demand Forecasting & Analysis

Encls.

CONSULTING AGREEMENT

THIS AGREEMENT made effective January 18, 2021.

B E T W E E N:

ENBRIDGE GAS INC.
("Enbridge")

- and -

GUIDEHOUSE CANADA LTD.
(the "Consultant")

WITNESSES THAT in consideration of the mutual covenants and agreements herein contained, the parties hereto covenant and agree as follows:

1. **Scope of Services**

   (a) During the term hereof (as hereinafter defined), the Consultant shall provide consulting services (the "Services") to Enbridge, on the terms and conditions set forth below.

   (b) The scope of work for specific projects to be undertaken by the Consultant at the request of Enbridge will be described in separate schedules referencing this Agreement, each of which shall become effective, be incorporated by reference and form an integral part of this Agreement upon the execution of each such schedule by Enbridge and the Consultant. The schedule for each project will specify the names of key individuals, scope of Services, deliverables, commencement and completion dates, rate of compensation and payment terms applicable to such project. Each schedule described above shall be prepared using a form similar to the attached Schedule "A".

2. **Compensation**

   In consideration of the Services and deliverables to be provided by the Consultant hereunder, and provided that the Consultant is not in default of its obligations hereunder, Enbridge shall remit to the Consultant all amounts required to be paid in accordance with the applicable schedule.

   Consultant shall be responsible for charging, collecting and remitting all applicable federal and provincial sales, use and value-added taxes in respect of the fees paid or payable to Consultant and, in particular, the goods and services tax ("GST") and harmonized sales tax ("HST") imposed under Part IX of the Excise Tax Act (the "ETA"), the Quebec sales tax ("QST") imposed under an Act respecting the Quebec Sales Tax (the "QSTA") and any provincial sales taxes ("PST"); and such taxes, if applicable, shall be shown separately on all invoices. Where Consultant is required to collect any GST/HST, QST or similar tax, Consultant shall provide Enbridge with the documentary evidence as prescribed pursuant to the ETA or QSTA, any successor provision thereto or any similar provision of any other taxing statute as is required to entitle Enbridge to claim an input tax credit, input tax refund, rebate, refund or any other form of relief in respect of such taxes.

   Where the Consultant is a non-resident of Canada for purposes of the Income Tax Act (Canada) (the "ITA"), with respect to the invoice or statement of Fees issued pursuant to any Schedule, the Consultant will identify the location where the Services are provided, separate Services performed in Canada from Services performed outside of Canada, identify the number of days Services were performed in Canada (including travel days to/from Canada) and, for Services performed in Canada, identify the physical location, indicating city and province, where such Services were performed. Where the non-resident Consultant has not obtained and provided to Enbridge a non-resident withholding tax waiver at such time as Enbridge makes any payment to the Consultant for Services, Enbridge shall withhold such percentage

of any payment as mandated under the ITA with respect to the Services provided in Canada or on the full invoice or statement amount where the Consultant has not clearly separated the Services performed in Canada from Services performed outside of Canada. Enbridge shall remit the withheld amount to Canada Revenue Agency, or its successor, in the manner and at the time required by the ITA. For further clarification, it is the Consultant's responsibility to obtain the tax waiver, if available. In the event that Enbridge is assessed for any non-resident withholding taxes payable, the Consultant agrees to forthwith reimburse Enbridge for such amount together with applicable interest and penalties, if any.

3. **Term**

Subject to earlier termination as provided for herein, the term of this Agreement shall commence on the day set forth above and expire on December 23, 2023 (hereinafter the "Term").

4. **Termination**

(a) Enbridge may terminate this Agreement or any schedule to this Agreement for convenience upon giving four (4) weeks written notice to the Consultant.

(b) Either party may terminate this Agreement in case of a breach by the other party of its obligations hereunder, provided that the breach is not cured within five (5) days of written notification by the non-defaulting party to the defaulting party setting out the particulars of the breach.

(c) Either party may terminate this Agreement upon written notice to the other party, if: (i) the other party is subject to proceedings in bankruptcy, or insolvency, whether voluntary or involuntary, (ii) a receiver is appointed in respect of all or a substantial portion of the other party's assets; or (iii) the other party assigns its property to its creditors or generally becomes unable to pay its debts as they become due.

Upon any termination of this Agreement, the Consultant shall deliver to Enbridge the results of all Services provided as of the date of termination, including completed or uncompleted deliverables for which payment has been received in accordance with the terms of this Agreement.

5. **Facilities**

Enbridge shall provide to the Consultant use of such office facilities as may be required by the Consultant, acting reasonably, to perform the Services during the Term.

6. **Reimbursement for Expenses**

In addition to the payments to be made pursuant to Section 2 hereof, Enbridge shall reimburse the Consultant for all reasonable expenses properly incurred by the Consultant in connection with the Services provided to Enbridge hereunder and that have been pre-approved by Enbridge in writing, including, without limitation, reasonable travel and other costs and expenses in connection therewith. Such pre-approved reasonable expenses incurred by the Consultant in rendering Services shall be reimbursed by Enbridge net of GST/HST. GST/HST shall be charged, where applicable, by the Consultant on the expenses incurred, net of the input tax credits/reimbursements for GST/HST claimed by the Consultant. Concurrently with its delivery of invoices to Enbridge as contemplated by Section 2 hereof, the Consultant shall submit to Enbridge invoices and statements setting out in reasonable detail the nature and amount of the expenses or costs incurred by the Consultant for which the Consultant claims reimbursement, and Enbridge shall within thirty (30) days of the receipt of such invoices and statements reimburse the Consultant for all approved invoiced expenses and costs. The Consultant shall provide to Enbridge copies of all documentation in support of invoiced expenses as Enbridge may request from time to time during the Term hereof.

7. **Independent Contractor**

Notwithstanding anything to the contrary herein contained, the Consultant shall not, for any purpose, be or be deemed to be an employee of Enbridge during the Term or at any time during which the Services described in Section 1 hereof are provided to Enbridge nor shall anything in this Agreement create or be

construed for any purpose as creating any relationship between Enbridge and the Consultant of employer and employee. Except as expressly provided herein, Enbridge shall not be liable to contribute to any employee benefit or pension plan or pay premiums for any policy or form of insurance whatsoever on behalf of the Consultant nor to pay any amounts or premiums on its behalf in respect of the Canada Pension Plan, Ontario Health Insurance Plan, Workplace Safety and Insurance Board or Employment Insurance, nor to deduct or withhold from source any amount from amounts payable by Enbridge to the Consultant hereunder in respect of any income tax obligation or liability payable by the Consultant to the Canada Revenue Agency. The Consultant agrees to indemnify and hold Enbridge harmless from and against any order, penalty, interest or tax that may be assessed or levied against Enbridge as a result of the failure or delay of the Consultant to file any return or information required to be filed by the Consultant by any law, ordinance or regulation relating to the Services performed by the Consultant herein.

8. **Confidential Information and Personal Information**

(a) For the purposes of this Section 8, the following definitions will apply:

(i) "Confidential Information", means all information pertaining to the business and affairs of Enbridge, its affiliates and subsidiaries, whether oral or written, furnished by Enbridge to the Consultant, its employees and representatives, whether furnished or prepared before or after the date of this Agreement, and includes all analysis, compilations, data, studies, reports or other documents prepared by the Consultant based upon or including any of the information furnished by Enbridge, but does not include information which:

A. is at the time of disclosure or thereafter becomes generally available to the public other than as a result of disclosure by the Consultant or anyone to whom the Consultant transmits the information;

B. is at the time of disclosure or thereafter becomes known or available to the Consultant on a non-confidential basis and not in contravention of applicable law from a source other than Enbridge that is entitled to disclose the information; or

C. is already in the possession of the Consultant or is lawfully acquired, provided that such information is not subject to another confidentiality agreement with, or obligations of secrecy to Enbridge.

(ii) "Person" includes individuals, partnerships, firms and corporations.

(b) Enbridge is furnishing the Confidential Information to the Consultant solely for the purpose of assisting the Consultant in the performance of Services which the Consultant provides to Enbridge. The Consultant shall not use the Confidential Information for any purpose other than the performance of Services provided to Enbridge.

(c) The Consultant acknowledges that the Confidential Information is the property of Enbridge, which is confidential and material to the interests, business and affairs of Enbridge and that disclosure thereof would be detrimental to the interests, business and affairs of Enbridge. Accordingly, the Consultant agrees that it shall maintain the confidentiality of the Confidential Information and that it shall not disclose the Confidential Information to any Person for any reason whatsoever except as expressly provided herein.

(d) The Consultant may disclose Confidential Information to the extent required by a court of competent jurisdiction or other governmental or regulatory authority or otherwise as required by applicable law, provided that the Consultant first give Enbridge prompt written notice (except where the governmental or regulatory authority has expressly ordered that no notice be given) and co-operate with and assist Enbridge in responding to the request or demand for disclosure.

(e) The Consultant acknowledges and agrees that Enbridge would be irreparably harmed if any provision of this Agreement is not performed by the Consultant in accordance with its terms. Accordingly, Enbridge shall be entitled to an injunction or injunctions to prevent breaches of any of the provisions of this Agreement and may specifically enforce such provisions by an action

instituted in a court having jurisdiction. These specific remedies are in addition to any other remedy to which Enbridge may be entitled at law or equity.

(f) If in the course of performing Services hereunder, the Consultant obtains or accesses personal information about an individual, including without limitation, a customer, potential customer or employee or contractor of Enbridge ("Personal Information") the Consultant agrees to treat such Personal Information in compliance with all applicable federal or provincial privacy or protection of personal information laws and to use such Personal Information only for purposes of providing the Services hereunder. Furthermore, the Consultant acknowledges and agrees that it will:

(i) not otherwise copy, retain, use, modify, manipulate, disclose or make available any Personal Information, except as required by applicable law;

(ii) establish or maintain in place appropriate policies and procedures to protect Personal Information from unauthorized collection, use or disclosure;

(iii) implement such policies and procedures thoroughly and effectively;

(iv) except as required for purposes of providing the Services hereunder, will not develop or derive, for any purpose whatsoever, any products in machine-readable form or otherwise, that incorporates, modifies, or uses in any manner whatsoever, any Personal Information; and

(v) upon completion of its Services for or on behalf of Enbridge, will at Enbridge's direction: A. return; or B. destroy all Personal Information and all copies and records thereof in its possession.

9. **Indemnification**

The Consultant hereby agrees to and shall:

(a) be liable to Enbridge and its directors, officers and employees, for all claims, liabilities, damages, costs, losses and expenses whatsoever which Enbridge or any of its directors, officers and employees may suffer, sustain or incur;

(b) indemnify and save harmless Enbridge, Enbridge's affiliated and subsidiary companies, and their directors, officers, agents, employees and representatives from and against any and all liabilities, claims, demands, damages, loss, costs and expenses (including without limitation all applicable solicitors' fees, court costs and disbursements, investigation expenses, adjusters' fees and disbursements) to or which any third party may suffer, sustain or incur, and

(c) However Consultant will only indemnify Enbridge, Enbridge's affiliated and subsidiary companies, and their directors, officers, agents, employees and representatives for direct damages connected with the liability and indemnity under 9.a. and 9.b. up to a maximum of two times the total Compensation due to Enbridge pursuant to this Agreement, unless caused by the gross negligence or willful misconduct of the Consultant. Notwithstanding any other provision in this clause Consultant shall not in any event be liable for any indirect, consequential, special, lost productivity or punitive damages, even if he has been advised of the possibility of such damages.

in respect of all matters or anything which may arise out of any act or omission directly or indirectly related to any breach of this Agreement by the Consultant, its employees or representatives.

10. **Work Product**

(a) For the purposes of this Section 10, "Work Product" shall include any of the following, which are developed in the course of or arise from the Services provided by the Consultant to Enbridge hereunder throughout the Term: (i) any deliverables produced under any schedule to this Agreement together with any and all notes, reports, research information, compilations, data specifications, designs, programs, documentation, software (including object code and source materials), development tools, products and other materials or things; (ii) any and all knowledge, know-how, techniques, inventions, processes, trade secrets, methodologies, approaches and other intangible intellectual property rights; and (iii) all designs, patent applications, issued patents, industrial design registrations, design patents, trade-mark applications, registered trade-marks and copyright which may relate thereto.

(b) For the purposes of this Section 10, "Consultant Materials" comprises any of the following, which were developed by the Consultant, at its own cost and expense in advance of and independent of this Agreement and as proven by the Consultant to be the case in the event of a dispute concerning the same: (i) any and all notes, research, information, data, specifications, designs, programs, documentation, software (including object code and source materials), development tools, products and other materials or things; (ii) any and all knowledge, know-how, techniques, inventions, processes, trade secrets, methodologies, approaches and other intangible intellectual property rights; and (iii) all designs, patent applications, issued patents, industrial design registrations, design patents, trade-mark applications, registered trade-marks and copyright which may relate thereto.

(c) All right, title and interest in and to the Work Product shall be the property of Enbridge. The Consultant shall ensure that any agent or employee of the Consultant shall have waived in writing all of his or her moral rights over any such Intellectual Property. During and after the Term of this Agreement, the Consultant shall from time to time as and when requested by Enbridge execute all papers and documents and perform other acts as necessary or appropriate to evidence or further document Enbridge's ownership of the Work Product and the intellectual property rights therein.

(d) The Consultant retains all right, title and interest in and to the Consultant Materials. The Consultant hereby grants to Enbridge a non-exclusive, perpetual, irrevocable, non-terminable, non-transferable, non-assignable and royalty-free license to copy, disclose, use, operate, maintain, repair, modify, enhance, make derivative works, license, sub-license and otherwise commercially exploit without limitation or restriction those Consultant Materials used in connection with the delivery of the Services or to the extent contained within any Work Product.

(e) The Consultant agrees to fully indemnify and hold harmless Enbridge from and against any and all: (i) claims, demands and actions; (ii) liabilities, damages or losses awarded by a court of competent jurisdiction or as agreed to as part of a settlement; and (iii) litigation costs and/or expenses (including reasonable legal fees and disbursements) reasonably incurred by Enbridge in connection with any claim that the Services or Work Product provided hereunder infringe any patent, copyright, trade secret or other right of any third party.

11. **Representations and Warranties**

(a) The Consultant represents, warrants and covenants with Enbridge that: (i) it will perform all Services in a good and workmanlike manner using reasonable care (at a level that is at least consistent with industry standards for the provision of similar services) and in accordance with the terms of this Agreement; (ii) it possesses the knowledge, skill and experience necessary for the provision and completion of the Services in accordance with the terms of this Agreement; and (iii) any deliverables provided hereunder shall conform to their relevant specifications as described in the applicable schedule.

(b) The Consultant agrees that under no circumstances will it interface a non-Enbridge computing device (including without limitation desktops, laptops, handheld device) with the Enbridge intranet or internet without obtaining the prior written approval of Enbridge. To the extent the deliverables produced hereunder involve the provision or development of any software application, interface or electronic data, the Consultant shall use commercially reasonable efforts to prevent the introduction of any virus to the hardware and computer systems upon which the application, interface or electronic data are to be installed. During the Term of this Agreement, the Consultant shall implement and run virus prevention and detection control procedures in accordance with industry standards.

(c) In addition to the policies described in Section 25, the Consultant shall ensure that it is familiar with and understands all of Enbridge's current policies, procedures and standards that are pertinent to the activities associated with the Services and which have been provided to the Consultant in advance of the execution of this Agreement.

12. **Subcontractors**

The Consultant shall not enter into any agreement with any other party to assist in the provision of the Services described in Section 1 hereof (hereinafter described as a "Subcontract") nor shall the Consultant allow any other party to perform such Services or any part thereof without first obtaining the consent in writing of Enbridge, which consent may be withheld by Enbridge, acting reasonably. Notwithstanding any approval or consent that may be provided by Enbridge in connection with any Subcontract, the Consultant shall not be relieved of any of its liabilities and responsibilities hereunder. Any party which enters into a Subcontract with the Consultant shall be required by the terms of such Subcontract to comply with and be bound by the obligations and responsibilities of the Consultant described hereunder and without restricting the generality of the foregoing, any Subcontract which has been entered into without the prior written consent of Enbridge shall be null and void and without force and effect.

13. **Insurance**

Save and except where Enbridge specifies otherwise in writing, the Consultant shall at its own expense maintain and keep in full force and effect during the Term hereof and for a period of two (2) years following the expiry of the Term or other termination of this Agreement:

(a) Commercial General Liability insurance having a minimum inclusive coverage limit, including personal injury and property damage, of at least Two Million Dollars ($2,000,000) per occurrence and in the aggregate. Enbridge Gas Inc. must be listed as the certificate holder and be added as an additional insured in the insurance policy, which should be extended to cover contractual liability, products/completed operations liability, owners'/ contractors' protective liability and must also contain a cross liability clause;

(b) Automobile Liability insurance on all vehicles used in connection with this Agreement and such insurance shall have a limit of at least Two Million Dollars ($2,000,000) in respect of bodily injury (including passenger hazard) and property damage inclusive of any one accident;

(c) Non-Owned Automobile Liability insurance and such insurance shall have a limit of at least Two Million Dollars ($2,000,000) in respect of bodily injury (including passenger hazard) and property damage, inclusive in any one accident; and

(d) such other insurance as Enbridge may in its discretion determine to be necessary, including, but not limited to, Professional Liability or Errors and Omissions insurance.

The Consultant shall forthwith after entering into this Agreement, and from time to time thereafter at the request of Enbridge, furnish to Enbridge a memorandum of insurance or an insurance certificate setting out the terms and conditions of each policy of insurance (all such policies of insurance being hereinafter described as the "Insurance Policies") maintained by the Consultant in order to satisfy the requirements of this section. At any time and from time to time at the request of Enbridge, the Consultant shall furnish Enbridge with one or more duly completed insurance certificates in the form requested by Enbridge to evidence the details of all the Insurance Policies. The Insurance Policies shall be arranged with insurers acceptable to Enbridge, acting reasonably, and shall contain such terms and conditions as are reasonably acceptable to Enbridge. The Consultant shall not cancel, terminate or materially alter the terms of any of the Insurance Policies without giving prior notice in writing to Enbridge. The Consultant shall provide Enbridge with 30 days written notice prior to cancellation or other material modification in the policy affecting the requirements of this Agreement. No such cancellation or modification shall affect Consultant's obligation to maintain the insurance coverage required by this Agreement.

14. **Compliance with Laws**

The Consultant agrees to comply with the Occupational Health and Safety Act (Ontario) and the Workplace Safety and Insurance Act (Ontario) and with all other prevailing federal, provincial and municipal laws and regulations or any other laws or regulations in force in any jurisdiction where the Services are performed (the "Laws") and which are applicable to the Consultant, its subcontractors and the Services provided hereunder, and the Consultant shall familiarize itself and procure all required permits and licenses and pay all charges and fees necessary or incidental to the due and lawful prosecution of this Agreement, and maintain all documentation as may be required by the Laws, and shall indemnify and save harmless Enbridge, its directors, officers, agents and employees thereof against any claim or liability from or based on the violation of any Laws, whether by the Consultant, its officers, employees, subcontractors, representatives or agents. The Consultant shall, from time to time, if requested by Enbridge, furnish Enbridge with evidence of such compliance, and in particular: (i) evidence from the Workplace Safety and Insurance Board, or the equivalent thereof in any jurisdiction where the Services provided hereunder are carried out, that the Consultant and any party with which it has entered into a Subcontract are in compliance with and have paid all assessments and other amounts owing pursuant to the workers' compensation legislation of such jurisdiction; and (ii) evidence of the Consultant's compliance with any training requirements under the Laws including, without limitation, the provision of such statements or certificates pertaining to the Consultant's compliance in the form(s) prescribed by Enbridge from time to time.

Enbridge is committed to compliance with the Accessibility for Ontarians with Disabilities Act, 2005, O.Reg. 429/07 and O.Reg. 191/11, the Enbridge Customer Service Policy for Providing Goods and Services to People with Disabilities and the Enbridge Integrated Accessibility Standards Policy (collectively the "AODA"). The Consultant shall ensure that it is in full compliance with all of its obligations under AODA. Without limiting the generality of the foregoing the Consultant shall ensure that all of its employees, agents, volunteers, or others engaged by the Consultant in the delivery of services under this Agreement receive training in connection with the requirements of the AODA. If requested to do so, the Consultant shall provide Enbridge with copies of its policies, practices, procedures, training materials and training records including the dates on when the training is provided, and the names of the individuals trained, and confirmation the Consultant has reported its compliance to the Ministry of Community and Social Services or such other governmental authority as provided in the AODA.

The Consultant will ensure that any personnel it assigns to work in Canada, where they are not a Canadian citizen or Canadian permanent resident of Canada, will obtain and maintain the lawful ability to engage in commercial activities in Canada through the issuance of the appropriate documentation from Canada Border Services Agency and Citizenship and Immigration Canada. The Consultant's personnel where necessary will obtain lawful work permits to engage in business-related activities as temporary foreign workers and will notify Enbridge if any applications for work permits and work permit renewals are refused. The Consultant will not send personnel to any Enbridge-related work site if they do not possess the necessary lawful permission to work in Canada. The Consultant will take full responsibility to secure the necessary documentation and produce such documentation when entering a Canadian work site of Enbridge.

15. **Waiver**

Either the Consultant or Enbridge may, in writing, extend the time for performance by the other and waive non-compliance or non-performance by the other of any of the other's obligations, covenants and agreements under this Agreement and any compliance therewith or performance thereof. However, no such extension or waiver shall operate so as to waive, diminish or reduce the scope of or otherwise affect any obligation, covenant or agreement of such other which is not the subject matter of such extension or waiver or, except to the extent of such extension or waiver, of the obligation, covenant and agreement which is the subject matter of such waiver. No act or failure to act of either the Consultant or Enbridge shall be or be deemed to be an extension or waiver of timely or strict performance by the other of the other's obligations, covenants and agreements under this Agreement except to the extent notice thereof is given to the other.

16. **Notice**

Any notice or other communication to be given under or pursuant to the provisions hereof or in any way concerning this Agreement shall be sufficiently given if reduced to writing and delivered to the person to whom such communication is to be given or sent by facsimile or electronic internet communication, addressed to such person at the address set forth below:

If to Enbridge:

ENBRIDGE GAS INC.
500 Consumers Rd
North York ON M2J 1P8
Attention: Hulya Sayyan, Senior Advisor Demand Forecasting & Analysis
Phone: 416-495-6332
Email: hulya.sayyan@enbridge.com

With a copy to: Law Department
Facsimile: 416-495-5994

If to the Consultant:

GUIDEHOUSE CANADA LTD.
100 King Street West, Suite 4950
Toronto Ontario M5X 1B1
Attention: Craig Sabine, Director
Phone: 647-288-5227 Ext.
Email: craig.sabine@guidehouse.com

or at such other address as may be specified therefor by proper notice hereunder. A notice or communication shall be deemed to have been sent and received on the day it is delivered personally or by courier or by facsimile or by electronic internet communication. If such day is not a business day or if the notice or communication is received after 5:00 PM (at the place of receipt) on any business day, the notice or communication shall be deemed to have been sent and received on the immediately following business day.

17. **Interpretation**

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. Headings used herein are for the convenience of reference only and shall not be considered in construing or interpreting this Agreement. The words "herein", "hereunder", "hereof" and other similar words refer to this Agreement as a whole and not to any particular paragraph. Any provision herein prohibited by law shall to the extent prohibited be ineffective without invalidating any other provisions hereof. All references to amounts of money in this Agreement and any schedule shall mean lawful currency of Canada.

18. **Assignment**

The Consultant may not assign this Agreement in whole or in part without the express prior consent in writing of Enbridge. This Agreement shall be binding upon and enure to the benefit of the successors and assigns of Enbridge.

19. **Use of Enbridge Name and Logo**

The Consultant shall not use or display Enbridge's name or any symbols, signs, trademarks and other marks denoting and identifying Enbridge in any manner whatsoever without the prior written authorization of Enbridge.

20. **Time of Essence**

Time shall be of the essence in the performance of the Services.

21. **Survival**

All warranties and indemnities contained in this Agreement, and the obligations contained in Section 8, shall survive the termination of this Agreement irrespective of the time of or party responsible for such termination, and such warranties, indemnities and obligations shall remain in full force and effect and be binding on the Contractor notwithstanding such termination.

22. **Further Assurances**

Each of the parties shall, from the time of the written request of the other party, do all such further acts and execute and deliver or cause to be done, executed or delivered all such further acts, deeds, documents, assurances and things as may be required, acting reasonably, in order to fully perform and to more effectively implement and carry out the terms of this Agreement.

23. **Entire Agreement**

This Agreement, including any schedules attached hereto, constitutes the entire agreement between the parties with respect to the subject matter set out herein and replaces any prior understandings or agreements, whether written or oral, regarding such subject matter. No change or modification of this Agreement is valid unless it is in writing and signed by both parties. No disclaimers, purchase order documents, invoices or other documents of the Consultant shall be binding upon Enbridge.

24. **Audit**

The Consultant shall, following no less than seven (7) business days advance notice in writing, provide to such auditors (including external auditors and Enbridge's internal audit staff or agents) as Enbridge may designate in writing, supervised access to the data, records and supporting documentation maintained by the Consultant with respect to the Services solely for the purpose of: (i) performing audits and inspections to enable Enbridge to satisfy applicable regulatory requirements or certify compliance with applicable laws; and (ii) to confirm that the Services are being provided in accordance with the terms of this Agreement. Enbridge and its auditors shall use commercially reasonable efforts to conduct such audits in a manner that will result in a minimum of inconvenience and disruption to the Consultant's business operations. In the event that if any such audit reveals any: (a) errors or deficiencies in the completion of the Services or invoicing of the Services; or (b) overpayments to the Consultant by Enbridge, then the Consultant shall forthwith correct such errors or deficiencies, including if applicable refunding any overpayment to Enbridge. The Consultant shall retain all records for ten (10) years from the date of expiration or earlier termination of this Agreement, or such longer period as Enbridge may require having regard to the nature of the Services.

25. **Enbridge Policies**

The Consultant acknowledges receipt of a copy of each of Enbridge Inc.'s Statement on Business Conduct for Enbridge Inc. and its Subsidiaries and Lifesaving Rules, each as amended from time to time (the "Policies"). The Consultant agrees to comply with the Policies in connection with its delivery of the Services described in this Agreement, and agrees that, if requested by Enbridge, it will ensure all personnel delivering the Services herein attend training on the Lifesaving Rules.

26. **ISNetworld Requirement**

If required by Enbridge, the Consultant shall subscribe with ISN Software Corporation as a registrant of ISNetworld ("ISN") or any successor service mandated by Enbridge from time to time, and maintain a performance grading within ISN that is acceptable to Enbridge (the "ISNetworld Requirement") and shall: (a) provide all records and information as required by ISN or Enbridge, including, but not limited to, training and qualification data of the Consultant personnel, including subcontractors and employees, relating to the Services; and (b) maintain compliance with the ISNetworld Requirement during the currency of this Agreement.

[remainder of page intentionally left blank]

27. **Counterparts and Execution**

This Agreement may be executed by the parties in separate counterparts, each of which when so executed and delivered will be deemed to be an original, and all such counterparts will together constitute one and the same instrument. Delivery of a signature by electronic transmission or by facsimile transmission, including by email delivery of a "portable document format" ("pdf") document, shall create a valid and binding obligation. This Agreement may be executed using electronic signatures.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first written above.

GUIDEHOUSE CANADA LTD.

By: ______________________
Name: Benjamin Grunfeld
Title: Partner

By: ______________________
Name: Craig Sabine
Title: Director
(Please print name and title of Signing Officer)

Witness: ______________________
Name:

(Witness required if Contractor is a Sole Proprietor)

ENBRIDGE GAS INC.

By: Gilmer Bashualdo-Hilario
Gilmer Bashualdo-Hilario (Feb 4, 2021 15:25 EST)
Name: Gilmer Bashualdo-Hilario
Title: Manager Economic Evaluation & Forecast

By: ______________________
Name: * *
Title: *

SCHEDULE A

**TO THE CONSULTING AGREEMENT BETWEEN
ENBRIDGE GAS INC. AND GUIDEHOUSE CANADA LTD.
Dated January 18, 2021**

This Schedule is made under the above referenced consulting agreement (the "Agreement") between ENBRIDGE GAS INC. ("Enbridge") and GUIDEHOUSE CANADA LTD. (the "Consultant").

1. **SCOPE OF SERVICES**

The Consultant will undertake the following Services:

Conduct a comparison of how other comparable North American natural gas utilities forecast their natural gas demand/consumption for their budget, and long-term strategic plans (including weather forecast, normalization, number of customers and average consumption per customer forecast); and collection of information about whether they use deferral accounts or other mechanisms to protect their revenues from the volumetric variances related to their demand, and weather forecast.

Consultant's Services shall include the establishment of a peer / focus group consisting of ten (10 utilities), through appropriate criteria (climate, size of utility, etc.). Consultant shall collect detailed information from such peer/focus group regarding each of the following:

- their weather forecast and normalization methodology;

- their number of customers/new customers forecast;

- their average consumption per customer forecast;

- their total consumption/demand forecast; and

- whether they use deferral accounts or other mechanisms to protect their revenues from the volumetric variances related to their demand and weather forecast.

2. **DELIVERABLES**

The Consultant will provide the following deliverables:

- A Written Report on Demand Forecast Benchmarking, provide detailed results of the Study in a table format.

- Write evidence and act as a witness in the Ontario Energy Board proceeding - either written, or in-person at the hearing.

3. **TERM AND COMMENCEMENT AND COMPLETION DATES**

This Schedule shall be effective as of January 18, 2021 and expire December 23, 2023, or such other date as the parties may mutually agree in writing.

4. **KEY PERSONNEL**

The Consultant will provide the following personnel to deliver the services set out above under Scope of Services:

Craig Sabine, Director in Charge
Dixon Grant, Project Manager
Peter Steele-Mosey, QA/QC Management & Forecasting SME
Judy Simon, Ontario Regulatory SME
Laurel Buchanan, Primary Researcher

5. **FEES AND PAYMENT TERMS**

Fees: As per attached Guidehouse Pricing sheet.

Expenses: N/A

The above fees and expenses cannot be exceeded without prior written approval from Enbridge.

Fees are payable by Enbridge within forty (40) days of receipt from the Consultant of an appropriate invoice setting out in reasonable detail the nature of the services provided.

[Remainder of page intentionally left blank; signature page to follow]

Dated as of January 18, 2021.

GUIDEHOUSE CANADA LTD.

By: ______________________
Name: Benjamin Grunfeld
Title: Partner

By: ______________________
Name: Craig Sabine
Title: Director
(Please print name and title of Signing Officer)

Witness: ______________________
Name:

(Witness required if Contractor is a Sole Proprietor)

ENBRIDGE GAS INC.

By: Gilmer Bashualdo-Hilario
Gilmer Bashualdo-Hilario (Feb 4, 2021 15:25 EST)
Name: Gilmer Bashualdo-Hilario
Title: Manager Economic Evaluation & Forecast

By: ______________________
Name: * *
Title: *

[redacted]

Price Breakdown by Task

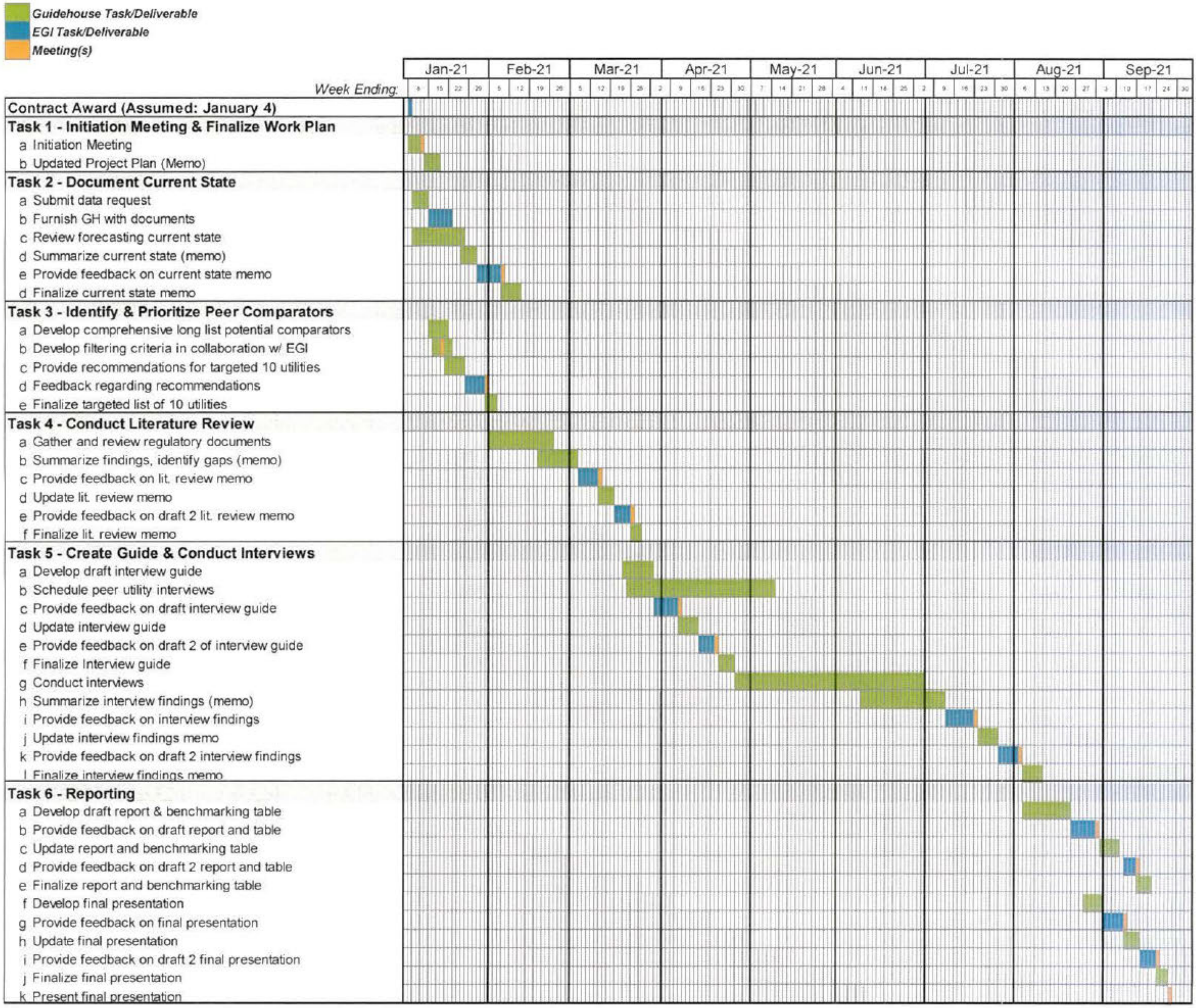
[redacted]

Task 1 Initiation Meeting and Work Plan
Task 2 Document Current State
Task 3 Identify & Prioritize Peer Panel
Task 4 Conduct Literature Review
Task 5 Interview Guide and Interviews
Task 6 Reporting

Price

EGI Demand Forecasting Benchmarking Project Schedule

Guidehouse



SCHEDULE B

TO THE CONSULTING AGREEMENT BETWEEN ENBRIDGE GAS INC. AND GUIDEHOUSE CANADA LTD. Dated January 18, 2021

This Schedule is made under the above referenced consulting agreement (the "Agreement") between ENBRIDGE GAS INC. ("Enbridge") and GUIDEHOUSE CANADA LTD. (the "Consultant").
All capitalized terms used in this Schedule have the meaning given to them in the Agreement.

1. **SCOPE OF SERVICES**

The Consultant will undertake the following Services, as further described in the Deliverables Section below:

EGI is seeking a comparative analysis of industry practices of relevant Canadian and U.S. LDCs for:

1. Weather and risk assumptions for Gas Supply planning

2. EGI is further seeking a review of utility best practices for design day demand modeling using the suggested design criteria, used for Gas Supply Planning in upstream contract sizing

3. EGI requires comprehensive written reports.

4. Participate at a half-day kickoff meeting at the outset to discuss existing criteria, methodologies, data and assumptions. This meeting will be held remotely.

5. Ongoing consultation to discuss preliminary results; provision of recommended revisions to design weather methodology and assumptions.

6. Assessment of the final results with accompanying presentation.

2. **DELIVERABLES**

The Consultant will provide the following deliverables:

Half-day kickoff meeting

Assessment of Final Results and Accompanying Presentation

Comprehensive Written Report

3. **COMMENCEMENT AND COMPLETION DATES**

This Schedule shall be effective as of March 8, 2021 and expire May 15, 2021, or such other date as the parties may mutually agree in writing.

4. **KEY PERSONNEL**

Craig Sabine, Director
Paul Moran, Associate Director
Peter Steele-Mosey, Associate Director
Dixon Grant, Senior Consultant
Laurel Buchanan, Consultant

5. **FEES AND PAYMENT TERMS**

Fees: [redacted]

Expenses: N/A

The above fees and expenses cannot be exceeded without the prior written approval of Enbridge.

Remainder of page intentionally left blank

Mercer

welcome to brighter

Project Initiation Form

The objective of this Project Initiation Form ("PIF") is to confirm the scope of our work and estimated fees for the Enbridge Gas Inc. pension and benefit plans projections for rate recovery application. This PIF is subject to the terms and conditions contained in our existing engagement letter dated March 24, 2014.

Project Details

1. **Client Name**: Enbridge Gas Inc. ("EGI")
2. **Project name**: EGI pension and benefit plans projections for 2022 - 2024
3. **Description of Mercer responsibilities**:

   Refer to the Appendix for a description of the anticipated scope of work.

4. **Description of client responsibilities:**

   Provide all necessary and reasonably requested co-operation to enable Mercer to provide the services.

5. **Estimated period of time over which work will be performed:** April 1, 2022 to July 31, 2022. The report is to be delivered on May 23, 2022.

Fee Structure

Mercer fees will be based on the billable hours and the hourly rates of the professionals doing the work. Every effort is made to delegate work to the level where the work can be competently and most efficiently performed. Each invoice is set by the billing consultant based on their judgment of the efficiency of the work and the value delivered. Where it is possible to deliver assignments in a more efficient way by leveraging work done on a shared basis across a number of clients, professional fees may reflect this shared development cost. In addition to our fees, Mercer also bills for necessary travel and other expenses related to the services requested. The hourly rate bands on which our fees are based are set out below:

[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

We estimate the total fees for the anticipated scope of work will be within the [redacted] This is an estimate only and fees will ultimately be based on the billable hours and hourly rates of the professionals doing the work.

Conclusion

We appreciate your business and look forward to working with you. Please acknowledge your agreement to the assignment terms by sending a confirmation e-mail. If we do not receive a response from you either accepting the terms or noting any concerns about any of the terms within five business days of your receipt of this PIF, we will assume that you have accepted the PIF and will perform the Services described in this PIF on the basis set out above.

MERCER (CANADA) LIMITED
solely in connection with the Services it provides pursuant to a PIF

By: ____________________

Name: Scott Thompson (Please Print) Date: April 22, 2022

Title: Principal

Appendix

Scope of Work

EGI's allocation of the following pension and benefit plans will be included in this work:

- Retirement Plan for Employees of Enbridge Inc. and Affiliates (the "EI RPP")
- Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "EGD RPP")
- Enbridge Supplemental Pension Plan (the "EI SPP")
- Supplementary Executive Retirement Plan of Enbridge Gas Distribution Inc. and Affiliates (the "EGD SERP")
- Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. (the "EGD SSERP")
- Pension Choices Plan for Employees of Westcoast Energy Inc. and Affiliated Companies (the "Pension Choices Plan")
- Union Gas Management & Supervisory Pension Plan (the "M&S Plan")
- Union Gas Bargaining Unit Plan (the "Bargaining Unit Plan")
- Union Gas Pension Plan for Salaried Employees Formerly Employed by Centra Gas Inc. (the "Salaried Plan")
- Union Gas Pension Plan - Group One (the "Group One Plan")
- Union Gas Pension Plan - Group Three (the "Group Three Plan")
- Supplemental Executive Retirement Plan (the "LSE SERP")
- Hold harmless for all DB participants (the "SEMPL")
- Enbridge Gas Distribution Inc.'s Non-pension Post Retirement Benefit Plan (the "EGD OPEB Plan")
- Spectra Energy Corp's Non-pension Post Retirement Benefit Plan (the "Spectra OPEB Plan")

The following summary is an overview of the anticipated work required for preparing the projections over the three year period from 2022 to 2024.

Project Phase	Scope
Planning	• Initial exploratory discussions • Internal planning and project management

Project Phase	Scope
Assumptions	Developing applicable assumptions as required based on market conditions at March 31, 2022[1] including: • Going concern discount rates • Provision for Adverse Deviation (Ontario plans only) • Expected return on assets • Annuity proxy rates • Commuted value interest rate *We have assumed that all other assumptions will be consistent with those approved by Enbridge's Pension Committee for filing actuarial funding valuations as at December 31, 2021.*
Data	• Preparing EI RPP DC membership data for use with future valuation projections • Extracting and reconciling assets from March 31, 2022 • Reconciling pending divestiture asset transfers as amount payable as at March 31, 2022 *We will rely on census data as at December 31, 2021/ January 1, 2022 used for Enbridge's funding valuations. Assets will be extracted from CIBC Mellon's Nexus portal.*
Future Valuations *EI RPP only*	• Preparing *future valuation* projections on going concern, solvency, and accounting bases for the years ending December 31, 2022 through December 31, 2023 based on revised assumptions as at March 31, 2022[1] • Adapting EI RPP funding projections for anticipated transition from Federal to Ontario jurisdiction • Extracting projected cash flows at each future valuation increment for use with the full yield curve pension cost calculations • Developing projected going concern, solvency and accounting balance sheets at annual increments to December 31, 2023 • Developing accumulated other comprehensive income (AOCI) balance reconciliations on corporate books and local books bases at annual increments to December 31, 2023 *No new entrants profiles are required since new members must join the defined contribution (DC) component of the EI RPP for first five years.*

[1] Or April 30, 2022 if applicable assumptions are available at the time the work is prepared.

Project Phase	Scope
Valuations *All other plans not relying on future valuations*	• Preparing valuations on going concern and accounting bases as at December 31, 2021 based on revised assumptions as at March 31, 2022[2]. • Extracting projected cash flows for use with the full yield curve pension cost calculations • Performing extrapolations to develop projected going concern, solvency and accounting balance sheets at annual increments to December 31, 2023 • Developing accumulated other comprehensive income (AOCI) balance reconciliations on corporate books and local books bases at annual increments to December 31, 2023 *In 2021, the Enbridge Pension Committee approved to apply to merge the M&S Plan, Bargaining Unit Plan, Salaried Plan, Group One Plan, and Group Three Plan into the EI RPP. As the applications have not yet been filed with the pension regulator, the merger will not be considered for these projections. This should not have a significant impact on the results.* *The actuaries performing this work may elect not to perform some or all of the funding basis extrapolations if it will not have a significant impact on the valuations.*
Projected cash contributions	• Determining estimated DB current service cost and special payment payments for 2023 to 2024 based on minimum funding requirements • Anticipating change in funding regulations for EI RPP due to change in jurisdiction • Calculating projected defined contribution (DC) requirements for 2023 and 2024 based on existing membership and reflecting assumed decrements • Calculating projected DC requirements for 2022 to 2024 based on *expected new entrants* *To the extent a Prior Year Credit Balance or special payment deferral is available, the actuaries performing the work will make a reasonable assumption on whether such a lever may be employed based on Enbridge's existing approach.*

[2] Or April 30, 2022 if applicable assumptions are available at the time the work is prepared.

Project Phase	**Scope**
Projected net periodic benefit costs under US GAAP	• Summarizing the annual net periodic benefit costs under US GAAP for 2022 • Determining estimated annual net periodic benefit costs under US GAAP for 2023 to 2024 using the full yield curve approach • Calculating estimated accumulated unrecognized actuarial loss/gain amortization amounts under corporate books and local books *When there is more than one participating employer in a plan, some components of EGI's net periodic benefit cost are a proportion of the total. As such, projections must be prepared for the total plans as well as for just EGI's share.*
Sensitivities	*No sensitivities or scenario analysis is included in this scope. Mercer and EGI should discuss if such analysis is preferred.*
Results and Report	• Prepare certified actuarial valuation report with all required results including: — Projected 2022 to 2024 net periodic benefit costs (on corporate basis) and expected funding contributions — Projected accounting balance sheet and AOCI (on corporate basis only) as at December 31, 2021, 2022 and 2023 • Include data, assumptions, methods and provisions disclosures so document is standalone • One results meeting with EGI to discuss report and projections • External to the report, a summary of the estimated AOCI balance as at December 31, 2023 on the local books basis, and the difference from corporate books basis. • Provide all results in Excel file format. *Actuaries are permitted to reference other external reports in their work in order to simplify disclosures. References to other external reports were used in the 2017 rate applications which the interveners requested copies of. Our objective is to avoid such requests with the report that will be filed this year. We understand this report will be filed with the OEB.*

The scope outlined in the table above includes the activities where it is anticipated Mercer consultants will be involved. Factors and considerations that may affect the estimated costs for this project include, but are not limited to:

- Any additional assumption changes beyond those anticipated with the data phase could increase costs

- All data is assumed to be reasonable and appropriate for these valuations. Significant additional data cleaning or manipulation beyond that anticipated in the data phase could increase costs.
- Unforeseen changes to standards of practice or applicable legislation
- Preparing sensitivity or alternative scenario analysis
- Preparing results on a stochastic basis
- Significant changes or additional content required for the report
- Incorporating any unforeseen divestitures or acquisitions
- Incorporating any future plan mergers

Mercer

welcome to brighter

Kenneth Yung, CFA
Partner

120 Bremner Boulevard, Suite 800
Toronto, Ontario
Tel. +1 416-868-2563
kenneth.yung@mercer.com

Project Initiation Form (PIF)

August 25, 2021

The objective of this Project Initiation Form (PIF) is to confirm the scope of our work and the compensation agreement for this project.

The terms and conditions of our existing agreement apply. However, with respect to the services described, should there be any difference between existing terms and conditions and those outlined here, the terms and conditions outlined in this PIF will apply.

Details

1. **Client Name:** Enbridge Inc. ("Enbridge")
2. **Project name or services:** Compensation Benchmarking for Regulatory Application
3. **Description of Mercer responsibilities:** Mercer will work with Enbridge to complete the following:

    1. **Project Planning**
        a. Project kick-off meeting with Enbridge and Mercer project teams to align on expectations, deliverables and timelines
        b. Collect and validate necessary data and information related to:
            i. Overall business, people and compensation strategy
            ii. Enbridge employee compensation data
            iii. Additional survey sources that Enbridge has access to (e.g., Willis Towers Watson "WTW" survey with relevant refinements)
        c. Bi-weekly project team updates (assumes 10)
        d. On-going project management (including updating detailed project plan and timeline)
    2. **Comparator Groups and Target Positioning**
        a. Draft comparator groups for non-union and union employees using available surveys
        b. 90-minute consultation with Enbridge project team to discuss preliminary comparator markets and target positioning
        c. Revise as necessary (assumes 1 round of revisions) and confirm
    3. **Benchmark Matching**
        a. Select ~300 non-union and ~30 union benchmark positions from Enbridge's Ontario, non-executive jobs
            i. 300 non-union jobs will cover almost all employees
            ii. 30 union jobs is expected to cover the majority of union employees
            iii. Fee estimate will be adjusted based on actual number of jobs included
        b. 60-minute meeting with project team to go over list (focusing on union job selection)
            i. 1 round of revisions

   c. Match all positions to survey sources
      i. Mercer expects to use 2 survey sources for non-union jobs: Mercer survey and WTW (may vary depending on comparator markets) in order to be able to capture a robust sample of relevant comparators and industries
      ii. Mercer expects to use 1 survey source for union jobs: Mercer survey
      iii. In addition, Mercer will leverage where applicable June 2021 custom survey sponsored by Hydro One, in which Enbridge participated and received summary results
   d. Up to 2 hours of meetings to review and revise matches with Enbridge project team

4. **Benchmarking Analysis and Report Delivery**
   a. Compile and analyze market data from relevant survey sources including:
      i. Base Salary
      ii. Short-Term Incentives
      iii. Total Cash Compensation
      iv. Long-Term Incentives
      v. Total Direct Compensation
   b. Research and compile collective bargaining rates for 30 union positions using Ontario collective agreements
   c. Prepare detailed findings report and excel data workbook with all market findings
   d. Review market data and findings in up to 3 hours of meetings
      i. Assumes 1 round of revisions
   e. Compile an executive summary report
      i. Assumes 1 round of revisions

4. **Description of client responsibilities:** Provide Mercer access to necessary data and information as required.
5. **Estimated period of time over which work will be performed:** The work will commence immediately upon acceptance of this PIF and will be completed by 31 December 2021. For accounting purposes only, we expect that this project will not extend beyond 30 June 2022.

Fee Structures

Mercer's estimated compensation for the services will be professional fees in the amount of [redacted] In addition to such compensation, Mercer also bills for necessary travel and other expenses related to the services requested and applicable taxes.

We appreciate your business and look forward to working with you on this project. Please acknowledge your agreement to the project terms by signing below.

MERCER (CANADA) LIMITED

By: Kenneth Yung

Name: Kenneth Yung Date: August 25, 2021

Title: Partner

ACKNOWLEDGED AND AGREED
ENBRIDGE INC.

By: Lisa Marusic

Name: Lisa Marusic Date: September 16, 2021
(Please Print)

Title: Manager Compensation

SCHEDULE "A-5"

FORM OF STATEMENT OF WORK

THIS STATEMENT OF WORK ("SOW") IS ENTERED INTO BETWEEN ENBRIDGE INC. ("SERVICE RECIPIENT") AND TOWERS WATSON CANADA INC. ("CONSULTANT") AS OF MARCH 1, 2017, AND IS SUBJECT TO THE CONSULTING SERVICES AGREEMENT BETWEEN ENBRIDGE INC. AND THE CONSULTANT DATED JANUARY 22, 2016 (THE "CSA"). ANY CAPITALIZED TERM USED IN THIS SOW BUT NOT DEFINED SHALL HAVE THE MEANING ASCRIBED TO SUCH CAPITALIZED TERM IN THE CSA.

The consultant will provide consulting services ("Services") to the Service Recipient on the terms set out below:

Term

The Term of this SOW is for the period commencing on March 1, 2017 and concluding December 31, 2020.

Renewal

The Service Recipient may, at its sole discretion, and upon notice given to the Consultant no later than thirty (30) days prior to the expiry of the Term of this SOW, extend the Term of this SOW for such further period as the parties agree.

Scope of Services

The Consultant shall provide the Services outlined in the Attachment(s).

Service Fees

The Services outlined in this SOW shall be performed primarily on a "fixed fee and expense" basis with general consulting on a "time and expense" basis as noted in the attachment, along with invoicing and payment terms, as described in the CSA. The fixed fees will be payable in monthly installments.

Key Personnel

The Consultant agrees that the Services shall be performed by Consultant's Health & Benefits Canadian and U.S. teams. Members of the U.S. team are employed by Consultant's affiliate Towers Watson Delaware Inc. Service Recipient must approve any additional personnel.

Additional Terms

In accordance with Section 2.2 or 2.3, as applicable, of the Agreement, this SOW shall be deemed to incorporate by reference and shall be subject to all the terms and conditions of the CSA, mutatis mutandis, with the same force and effect as if the terms and conditions of the CSA were fully set out in this SOW, subject to any express amendments, modifications or inclusion of additional terms set forth in this SOW.

We estimate that this engagement will be completed during 2017-2020, and the annual activities for each year will be completed in that calendar year. We will work closely with you on scheduling and use reasonable efforts to adhere to this schedule, but we cannot guarantee that this schedule will be met.

Each Party acknowledges that it has read this SOW, understands it and agrees to be bound by its terms and conditions.

Counterpart

This SOW may be executed in any number of counterparts and all such counterparts shall, for all purposes, constitute one agreement binding on all parties hereto notwithstanding that parties are not signatories to the same counterpart, provided that each party has signed at least one counterpart. This SOW may be executed and delivered by facsimile transmission or electronic transmission in .pdf or similar universally readable format and the parties hereto may rely on all such facsimile or electronically provided signature pages as though the signatures on such facsimile or electronically provided signature pages were original signatures.

IN WITNESS WHEREOF the parties hereto have executed this SOW on the day and year first above written.

TOWERS WATSON CANADA INC.

Signature:

Print Name: Wendy Poirier

Title: Region Leader, Health & Benefits Canada

Date: March 6, 2017

ENBRIDGE INC.

Signature:

Print Name: Chris Boniface.

Title: Director Rewards + Analytics

Date: July 3, 2017

ONGOING HEALTH AND BENEFITS CONSULTING – Canadian Benefits

Description of Services:

The assignment will encompass the services outlined below:

Annual Strategic Planning Meeting **No charge**

- Half day annual strategic planning meeting for Canada and U.S. combined
  - Review plan objectives and performance against goals
  - Discuss key market trends, vendor developments and initiatives
  - Agree on project plan for all activities during the upcoming year

Benefit Plan Pricing

Integrated Flex Plan and Retiree Plan – Initial (for 2018) [redacted]

- Analyze actual health and dental claims experience for 2016 and project claims costs for 2017 under proposed flex plan
- Update overall program costs for 2017 for Enbridge and Spectra Energy separately and combined, incorporating:
  - Spectra Energy and Enbridge enrolment statistics for 2017
  - Current premium rates for 2017 for insured benefits
  - Estimate 2017 claims experience for health and dental benefits
- Project overall program costs for 2018 on a combined basis, taking into consideration proposed premium rates for 2018 for insured benefits and estimated 2018 claims experience for health and dental benefits
- Determine appropriate flex credits and price-tags for proposed flex plan for 2018 plan year
- Review current retiree health plan experience and project for upcoming plan year in order to determine appropriate price-tag for retirees
- Prepare presentation and meet with Enbridge to discuss results

Integrated Flex Plan and Retiree Plan – Ongoing [redacted]

- Gather and analyze individual enrolment statistics for the current plan year for employees under the integrated flex plan
- Analyze actual health and dental claims experience for prior plan year and project for claims cost upcoming plan year
- Update overall program costs for current and upcoming plan year to reflect updated enrolment statistics (Enbridge and Spectra Energy employees under integrated flex plan) as well as premium rates for insured benefits, updated claims experience for health and dental benefits and any required changes to credits and price-tags
- Review current retiree health plan experience and project for upcoming plan year in order to determine appropriate price-tag for retirees
- Prepare presentation and meet with Enbridge to discuss results

Legacy Spectra Energy Flex Plan [redacted]

- Gather and analyze individual enrolment statistics for the current plan year for employees remaining under the legacy Spectra Energy flex plan
- Analyze actual health and dental claims experience for prior plan year and project for upcoming plan year
- Update overall program costs for the prior plan year based on actual health and dental claims experience to determine if refund to employees is required
- Update overall cost projections for current and upcoming plan year to reflect updated enrolment statistics as well as proposed premium rates for insured benefits, updated claims experience for health and dental benefits and any required changes to credits and price-tag
- Prepare presentation and meet with Enbridge to discuss results

Annual Financials

Legacy Enbridge Plans [redacted]

- Audit annual financial statements provided by the vendor, for East and West separately, for the refund accounted plans (basic life insurance and LTD), with respect to accuracy and reasonableness of the following:
  - Premium and claims
  - Waiver of premium, disabled life and IBNR reserves
  - Retention and pooling charges and pooling charges
- Check reasonableness of premiums and claims for fully pooled benefits (optional life insurance)
- Audit annual ASO statements provided by vendor for health and dental benefits for accuracy and reasonableness of ASO and pooling charges
- Determine final account balances for refund accounted plans in termination/run-off accounting and outline responsibility of existing disabled claimants (assuming life insurance and LTD moved to another insurer)
- Prepare presentation and meet with Enbridge to review results

Legacy Spectra Plans [redacted]

- Audit annual financial statements provided by Manulife for basic life insurance (7 plans), LTD (5 plans), health (8 plans), dental (7 plans) and HCSA (4 plans), with respect to accuracy and reasonableness of the following:
  - Premium and claims
  - Waiver of premium, disabled life and IBNR reserves
  - Retention/ASO charges and pooling charges
  - Tax and interest calculations
- Review in-line transfers between operating companies (Westcoast, Union Gas and St. Clair Pipelines) and benefits, CFR and deposit account balances to confirm Manulife has transferred funds appropriately
- Check reasonableness of premiums and claims for fully pooled benefits (optional life and AD&D)
- Determine actual HCSA "forfeitures" for the plan year
- Determine final account balances for refund accounted and ASO plans in termination/run-off accounting and outline responsibility of existing disabled claimants
- Prepare presentation and meet with Enbridge to review results

New Integrated Plans [redacted]

- Audit annual financial statements provided by the vendor, for East and West separately, for the refund accounted plans (basic life and LTD), with respect to accuracy and reasonableness of the following:
  - Premium and claims
  - Waiver of premium, disabled life and IBNR reserves
  - Retention and pooling charges and pooling charges
- Check reasonableness of premiums and claims for fully pooled benefits (optional life insurance)
- Audit annual ASO statements provided by vendor for health and dental benefits for accuracy and reasonableness of ASO and pooling charges
- Prepare presentation and meet with Enbridge to review results

Renewal Analysis (Illustrative renewal during guarantee period) [redacted]

- Review "illustrative renewal analysis prepared by vendor for the life insurance and LTD benefits to determine potential impact on premium rates after expiration of rate guarantees
- Prepare high level presentation and meet with Enbridge

Quebec Taxable Benefit Calculations [redacted]

- Calculate annual taxable benefits for Quebec employees and retirees for health and dental

General Health and Benefits Consulting **Time & Expense**

- Provide additional consulting to Enbridge with respect to Health & Benefit programs, as needed throughout the year
- Assist Enbridge with policy standardization and compliance efforts, as needed
- Respond to ad hoc questions as required

Summary of Projects for Canada (CAD)				
Project	**2017**	**2018**	**2019**	**2020**
Flex Benefit Plan Pricing ■ Integrated flex plan - initial ■ Integrated flex plan - ongoing ■ Legacy Spectra Energy flex plan	[redacted]			
Annual Financials ■ Legacy Enbridge plans ■ Legacy Spectra Energy plans ■ New integrated plans				
Renewal Analysis				
Quebec Taxable Benefit Calculation				
TOTAL				

* Will be completed under Spectra Energy scope of work for 2017.
** May decrease or be eliminated depending on success of union negotiations.
*** May increase if rate guarantees are only three years and full renewal is required.

ONGOING HEALTH AND BENEFITS CONSULTING – U.S. Benefits

Description of Services

The assignment will encompass the services outlined below:

Annual Strategic Planning Meeting **No charge**

- Half day annual strategic planning meeting for Canada and U.S. combined
  - Review plan objectives and performance against goals
  - Discuss key market trends, vendor developments and initiatives
  - Agree on project plan for all activities during the upcoming year

Benefit Plan Strategy and Plan Management – Initial

Abbreviated Process – Initial (for 2018) [redacted]

- Brief strategic planning update
  - Review senior leadership changes to harmonization strategy
  - Review benchmarking information against key peer group, including annual Oil and Gas BenVal, Financial Benchmark Survey as well as other surveys
- Provide monthly Experience Monitoring Reports to track actual against budget for the current plan year (either March – December 2017 or January – December 2017 if preferred)
- Provide peer technical review of open enrollment communications, including description of benefits provided, employee premium rates and required legal notices

Regular Process – Ongoing [redacted]

- Benchmarking review meeting
  - Review benchmarking information against key peer group, including annual Oil and Gas BenVal, Financial Benchmark Survey as well as other surveys
  - Discuss key market trends in the oil and gas industry
- Develop and review wellness program strategy
- Provide monthly Experience Monitoring Reports to track actual against budget
- Provide peer technical review of open enrollment communications, including description of benefits provided, employee premium rates and required legal notices

Benefit Plan Pricing

Integrated Benefit Plans – Initial (for 2018) [redacted]

- Gather and analyze enrollment statistics for the current plan year
- Analyze actual health and dental claims experience for prior plan year and project for upcoming plan year
- Annual plan pricing and cost projections for the harmonized active program for Enbridge combined with Spectra and legacy Spectra retirees
  - Develop benefit plan projected cost (fully insured equivalent) for each calendar year, using actual claim experience, national trend and underwriting data
  - Provide annual cost information for internal budgets
  - Set 1-2 pricing scenarios and estimate effect on total costs and employee contributions
- Prepare drafts of materials for leadership team approval and attend leadership meetings as requested
- Complete Morneau Shepell rate template for legacy Spectra retirees
- Provide prescription drug creditable coverage testing for the active health insurance plan
- Provide quarterly IBNR estimates for active medical, retiree medical, and dental plans
- Assist with information gathering for plan audit

Integrated Benefit Plans – Ongoing [redacted]

- Gather and analyze enrollment statistics for the current plan year
- Analyze actual health and dental claims experience for prior plan year and project for upcoming plan year
- Annual plan pricing and cost projections for Enbridge actives and legacy Spectra retirees (note that it is anticipated that legacy Spectra retirees will remain in the self-funded plan until January 1, 2020)
  - Develop benefit plan projected cost (fully insured equivalent) for each calendar year, using actual claim experience, national trend and underwriting data
  - Provide annual cost information for internal budgets
  - Set 3-4 pricing scenarios and estimate effect on total costs and employee contributions
- Prepare drafts of materials for leadership team approval and attend leadership meetings as requested
- Complete Morneau Shepell rate template for legacy Spectra retirees

- Provide prescription drug creditable coverage testing for the active health insurance plan
- Provide quarterly IBNR estimates for active medical, retiree medical, and dental plans
- Assist with information gathering for plan audit

Vendor Management

Legacy Enbridge and Spectra Programs Separately – Initial (for 2018) [redacted]

- Assist Enbridge with managing and resolving escalated employee issues and systemic problem resolution with vendors
- Facilitate annual vendor performance meetings including work with vendors to create annual vendor presentations that are technically accurate and provide meaningful, customized information, attend annual vendor performance meeting and manage meeting follow ups for:
  - BCBSTX for both Spectra and Enbridge
  - UMR for Spectra post-65 retirees
  - CVS Heath
  - Hartford
  - ActiveHealth
  - Preventure

Integrated Benefit Plans – Ongoing [redacted]

- Review annual vendor performance
  - Review and evaluate service provider contractual arrangements (e.g., performance guarantees, rebates) and provide recommendations
  - Assist Enbridge in managing and resolving escalated employee issues and systemic problem resolution assistance with vendors
  - Monitor vendor's quality of service and institute quality standards including financial penalties
  - Provide Enbridge with updated vendor contact list
  - Maintain an log of open vendor issues with Blue Cross/Blue Shield of Texas (BCBSTX)
- Facilitate annual vendor performance meetings including work with vendors to create annual vendor presentations that are technically accurate and provide meaningful, customized information, attend annual vendor performance meeting and manage meeting follow ups for:
  - BCBSTX
    - Participate on quarterly/semi-annual calls and meetings to review open issues

  - UMR (until post-65 retiree program modified, assumed January 1, 2020)
  - Hartford or other life insurance/disability carrier
  - Preventure or other wellness plan provider
- Request and analyze vendor renewals (as required)
- Note that all pharmacy management activities will occur through the RxCollaborative

Compliance [redacted]

- Ongoing compliance consulting
  - Provide consulting relative to health and insurance plans, including compliance, due diligence and support, e.g., contracts, trusts, 5500 Schedule As, daily administrative issues
  - Complete annual Form 5500
  - Assist Enbridge in complying with existing state or federal and state legislation that may impact your health and welfare programs
  - Review existing SPDs for legal/regulatory required changes
- Provide Enbridge with annual compliance calendar and timely updates regarding due dates for any filings
- Provide legislative/legal/industry updates
  - Provide data on current and proposed state and federal legislation and provide interpretation guidance
  - Provide research materials on various topics, as necessary

Medicare Part D Attestation [redacted]

- Medicare Part D attestation for legacy Spectra Energy retiree populations
  - Includes Attestation Report and testing for all legacy Spectra plans
- Acting as Account Manager for RDS filing
- Coordinating data submission and quarterly reimbursement requests

General Health and Benefits Consulting **Time and Expense**

- Provide additional consulting Enbridge with respect to Health and Benefit programs
- Assist Enbridge with policy standardization and compliance efforts
- Ad hoc questions and other consulting activities as requested

Summary of Projects for US (USD)				
Project	2017	2018	2019	2020
Benefit Plan Strategy and Plan Management ▪ Initial ▪ Ongoing	[redacted]			
Benefit Plan Pricing ▪ Initial ▪ Ongoing				
Vendor Management ▪ Initial ▪ Ongoing				
Compliance				
Medicare Part D				
TOTAL				

ENBRIDGE

Enbridge
200, 425 – 1st Street SW
Calgary, Alberta T2P 3L8
Canada

November 30, 2020

Willis Towers Watson Inc.
308 4 Avenue SW
Suite 2900
Calgary, AB
T2P 0H7

Attention: P. Charles Allegro

RE: Renewal of March 1, 2017 Statement of Work

Dear Charlie:

Further to the:

- Statement of Work dated March 1, 2017 (the "SOW"); and
- the Consulting Services Agreement dated January 22, 2016 (the "CSA"),

entered into by our two firms, please accept this letter as Enbridge Inc.'s exercise of the renewal option set out in the SOW. In particular, the SOW states:

> "The Service Recipient may, at its sole discretion, and upon notice given to the Consultant no later than thirty (30) days prior to the expiry of the Term of this SOW, extend the Term of this SOW for such further period as the parties agree",

Enbridge Inc. wishes to extend the term of the SOW to December 31, 2023 including the following modifications:

Summary of Projects for Canada (CAD)			
Project	**2021**	**2022**	**2023**
Flex Benefit Plan Pricing • Integrated flex plan – ongoing • Legacy Spectra Energy flex plan • Legacy Enbridge flex plan	[redacted]		
Annual Financials • Enbridge plans			
Renewal Analysis			
Retiree Renewal Analysis			
Quebec Taxable Benefit Calculation			
TOTAL			

* May decrease or be eliminated depending on success of union negotiations.

Summary of Projects for US (USD)			
Project	**2021**	**2022**	**2023**
Benefit Plan Strategy and Plan Management • Ongoing	[redacted]		
Benefit Plan Pricing • Ongoing			
Vendor Management • Ongoing			
Compliance			
Medicare Part D			
Non-discrimination testing			
TOTAL			

The project descriptions are the same as noted in the SOW except for the Non-discrimination Testing project which is described below.

Non-Discrimination Testing

Enbridge has requested Willis Towers Watson perform nondiscrimination testing under IRC §125, 105, 129 and 79. The specific nondiscrimination testing Willis Towers Watson will perform on behalf of Enbridge is provided below:

SECTION 125 CAFETERIA PLANS

- Eligibility Test
- Contributions or Benefits Test (including utilization)
- Concentration Test

SECTION 105 AMOUNTS RECEIVED UNDER ACCIDENT AND HEALTH PLANS

- Eligibility Test
- Benefits Test

SECTION 129 DEPENDENT CARE ASSISTANCE PROGRAMS

- Eligibility Test
- Contributions or Benefits Test
- 25% Concentration Test
- Average Benefits Test (i.e., 55% utilization test)

SECTION 79 GROUP TERM LIFE INSURANCE PURCHASED FOR EMPLOYEES

- Eligibility Test
- Benefits Test

The above is subject to the discounting agreement we have in place with Willis Towers Watson in the email to Kendra Hand dated July 28, 2020 from Charlie Allegro (attached) except the H&B consulting services will be discounted by 15% instead of 10% until the end of 2021. Further the invoice process will be revised in accordance with the email to Ryan Stelmaschuk dated October 19, 2020 from Charlie Allegro (attached).

Please provide Willis Towers Watson Inc.'s acknowledgement and agreement to this extension by signing a copy of this letter in the place indicated below and forwarding a copy to my attention via email.

Sincerely,

Ryan Stelmaschuk

Ryan Stelmaschuk
Manager, Pensions & Benefits

Willis Towers Watson Inc. agrees to the extension and other modifications of the SOW as set forth in this letter.

Per: ______________________________
P. Charles Allegro
Senior Director, Client Management

cc: Henry Noey – Willis Towers Watson
Victoria Kohout – Willis Towers Watson
Kathy Elmore – Willis Towers Watson

SCHEDULE C

TO THE CONSULTING AGREEMENT BETWEEN ENBRIDGE GAS INC. AND GUIDEHOUSE CANADA LTD. Dated January 18, 2021

This Schedule is made under the above referenced consulting agreement (the "Agreement") between ENBRIDGE GAS INC. ("Enbridge") and GUIDEHOUSE CANADA LTD. (the "Consultant"). All capitalized terms used in this Schedule have the meaning given to them in the Agreement.

1. **SCOPE OF SERVICES**

The Consultant will undertake the following Services, as further described in the Deliverables Section below:

Conduct an independent review of EGI's CSS cost allocations

The required tasks and objectives of the review are to:
1. Obtain an understanding of the CAM implemented by Enbridge Inc. to allocate costs to EGI and other Enbridge business units.

Examples of information that is available to assist in obtaining an understanding include:
a. The Intercorporate Services Agreement between EI and EGI effective January 1, 2019 (ISA)
b. CAM policy and allocation documents
c. Documentation outlining services received

2. Review relevant OEB decisions and directives, including those related to OEB-regulated electric utilities.

3. Review and assess the reasonableness and appropriateness of CSS cost allocations received by EGI under CAM in the context of the OEB's three-pronged test established in EBRO 493/494 and other relevant OEB precedents.
a. When reviewing CAM, consider whether:
i. the service and level of service is specifically required by EGI
ii. the costs are allocated based on cost causality and appropriate cost drivers
iii. the cost to provide the service internally is reasonable relative to the cost to acquire the service externally on a stand-alone basis (benchmarking)
iv. there are scale economies, and
v. the CSS fall within the range of fair market value for an organization of Enbridge's size and complexity

4. Review and assess how the ISA and CAM comply with the OEB's past decisions and the ARC

5. Provide a written report and detailed financial analysis (including benchmarking results) supporting conclusions reached

6. The following related work will be carried out under separate engagement, if and as necessary, after the delivery of the final report:
a. Responses to information requests resulting from the regulatory process
b. Defend findings before the OEB, as an expert witness

Quality of Work
The quality of all documentation must be suitable for the purposes of regulatory filings, as noted above. Access to the data, records and supporting documentation related to work performed must also be provided to auditors (including external and our internal audit staff or agents) if requested.

2. **DELIVERABLES**

The Consultant will provide the following deliverables:

A written report that provides descriptions and outcomes of the CAM study. The proponent may need to participate in OEB proceedings as an expert witness – either through written submissions or in person.

3. **COMMENCEMENT AND COMPLETION DATES**

This Schedule shall be effective as of June 21, 2021 and expire December 23, 2023, or such other date as the parties may mutually agree in writing.

4. **KEY PERSONNEL**

Craig Sabine, Director
Dixon Grant, Managing Consultant
David Cohen, Associate Director
Matt Croft, Managing Consultant
Allan Ng, Managing Consultant
Navodi Athapaththu, Consultant

5. **FEES AND PAYMENT TERMS**

[redacted]

If additional work is required, unrelated to OEB proceedings, or if the Consultant is required to participate in OEB proceedings as an expert witness, either through written submissions or in person, such additional work shall be in accordance with the applicable rate table as in the attached Hourly Rates.

Expenses: N/A

The above fees and expenses cannot be exceeded without the prior written approval of Enbridge.

Fees are payable by Enbridge within sixty (60) days of receipt from the Consultant of an appropriate invoice setting out in reasonable detail the nature of the services provided.

Dated as of June 21, 2021.

GUIDEHOUSE CANADA LTD.

By: ______________________
Name: Craig Sabine
Title: Director

By: ______________________
Name: Benjamin Grunfeld
Title: Partner
(Please print name and title of Signing Officer)

Witness: ______________________
Name:

(Witness required if Contractor is a Sole Proprietor)

ENBRIDGE GAS INC.

By: Chris Tuckwell
Chris Tuckwell (Jun 15, 2021 10:49 EDT)
Name: Chris Tuckwell
Title: Director Accounting UPO

By: ______________________
Name: * *
Title: *

Hourly Rates for Additional Work (OEB proceedings, etc.)

Rates Applicable for Additional non-OEB Hearing Related Work

Role Description	Estimated Number of Hours	Hourly Rates in CDN $ 2021 ($/hour)	2022 ($/hour)	2023 ($/hour)
Partner		[redacted]	[redacted]	[redacted]
Director		[redacted]	[redacted]	[redacted]
Associate Director		[redacted]	[redacted]	[redacted]
Managing Consultant		[redacted]	[redacted]	[redacted]
Senior Consultant		[redacted]	[redacted]	[redacted]
Consultant		[redacted]	[redacted]	[redacted]

Rates above are discounted specifically for any incremental assignments, or out of scope work found to be necessary and that is not related to testimony or responding to intervenor request completed on a time and materials basis

Rates Applicable to OEB Hearing Related Work

Role Description	Estimated Number of Hours	Hourly Rates in CDN $ 2021 ($/hour)	2022 ($/hour)	2023 ($/hour)
Partner			[redacted]	[redacted]
Director			[redacted]	[redacted]
Associate Director			[redacted]	[redacted]
Managing Consultant			[redacted]	[redacted]
Senior Consultant			[redacted]	[redacted]
Consultant			[redacted]	[redacted]

ENBRIDGE

50 Keil Drive North, Box 2001
Chatham ON N7M 5M1

Danielle Dreveny, Manager Capital FP&A
Tel: 519-436-4600 ext. 5002330
Email: Danielle.Dreveny@enbridge.com

April 23, 2021

CONCENTRIC ADVISORS ULC
200 Rivercrest Drive S. E.
Calgary Alberta T2C 2X5

Dear Sir / Madam,

RE: Consulting Agreement with Enbridge Gas Inc.

Attached please find for signature our Consulting Agreement. Kindly arrange to have the Agreement and the attached Schedule signed. Please ensure you read and understand all of the terms and conditions of the Agreement, as well as the enclosed Statement on Business Conduct and Lifesaving Rules.

We will also require the following:

- A current clearance certificate or letter of exemption from the Ontario Workplace Safety and Insurance Board ("WSIB"). If your employees are in a jurisdiction other than Ontario, please provide equivalent proof of coverage, and new proof of coverage must be filed with us upon expiry/renewal of such proof of coverage.

Please return the applicable WSIB document noted above, together with a signed copy of the Consulting Agreement and a signed copy of the Schedule, promptly following receipt of this letter. Upon receipt of all the documents in our office, we will execute the Agreement and a PDF copy of the Agreement will be returned to you for your records.

If you have any questions, please contact me at the above-noted telephone number.

Sincerely,

Danielle Dreveny
Manager Capital FP&A

Encls.

CONSULTING AGREEMENT

THIS AGREEMENT made effective April 9, 2021.

BETWEEN:

ENBRIDGE GAS INC.
("Enbridge")

- and -

CONCENTRIC ADVISORS ULC
(the "Consultant")

WITNESSES THAT in consideration of the mutual covenants and agreements herein contained, the parties hereto covenant and agree as follows:

1. **Scope of Services**

   (a) During the term hereof (as hereinafter defined), the Consultant shall provide consulting services (the "Services") to Enbridge, on the terms and conditions set forth below.

   (b) The scope of work for specific projects to be undertaken by the Consultant at the request of Enbridge will be described in separate schedules referencing this Agreement, each of which shall become effective, be incorporated by reference and form an integral part of this Agreement upon the execution of each such schedule by Enbridge and the Consultant. The schedule for each project will specify the names of key individuals, scope of Services, deliverables, commencement and completion dates, rate of compensation and payment terms applicable to such project. Each schedule described above shall be prepared using a form similar to the attached Schedule "A".

2. **Compensation**

   In consideration of the Services and deliverables to be provided by the Consultant hereunder, and provided that the Consultant is not in default of its obligations hereunder, Enbridge shall remit to the Consultant all amounts required to be paid in accordance with the applicable schedule.

   Consultant shall be responsible for charging, collecting and remitting all applicable federal and provincial sales, use and value-added taxes in respect of the fees paid or payable to Consultant and, in particular, the goods and services tax ("GST") and harmonized sales tax ("HST") imposed under Part IX of the Excise Tax Act (the "ETA"), the Quebec sales tax ("QST") imposed under an Act respecting the Quebec Sales Tax (the "QSTA") and any provincial sales taxes ("PST"); and such taxes, if applicable, shall be shown separately on all invoices. Where Consultant is required to collect any GST/HST, QST or similar tax, Consultant shall provide Enbridge with the documentary evidence as prescribed pursuant to the ETA or QSTA, any successor provision thereto or any similar provision of any other taxing statute as is required to entitle Enbridge to claim an input tax credit, input tax refund, rebate, refund or any other form of relief in respect of such taxes.

   Where the Consultant is a non-resident of Canada for purposes of the Income Tax Act (Canada) (the "ITA"), with respect to the invoice or statement of Fees issued pursuant to any Schedule, the Consultant will identify the location where the Services are provided, separate Services performed in Canada from Services performed outside of Canada, identify the number of days Services were performed in Canada (including travel days to/from Canada) and, for Services performed in Canada, identify the physical location, indicating city and province, where such Services were performed. Where the non-resident Consultant has not obtained and provided to Enbridge a non-resident withholding tax waiver at such time as Enbridge makes any payment to the Consultant for Services, Enbridge shall withhold such percentage

of any payment as mandated under the ITA with respect to the Services provided in Canada or on the full invoice or statement amount where the Consultant has not clearly separated the Services performed in Canada from Services performed outside of Canada. Enbridge shall remit the withheld amount to Canada Revenue Agency, or its successor, in the manner and at the time required by the ITA. For further clarification, it is the Consultant's responsibility to obtain the tax waiver, if available. In the event that Enbridge is assessed for any non-resident withholding taxes payable, the Consultant agrees to forthwith reimburse Enbridge for such amount together with applicable interest and penalties, if any.

3. **Term**

Subject to earlier termination as provided for herein, the term of this Agreement shall commence on the day set forth above and expire on December 31, 2023 (hereinafter the "Term").

4. **Termination**

(a) Enbridge may terminate this Agreement or any schedule to this Agreement for convenience upon giving two (2) weeks written notice to the Consultant.

(b) Either party may terminate this Agreement in case of a breach by the other party of its obligations hereunder, provided that the breach is not cured within five (5) days of written notification by the non-defaulting party to the defaulting party setting out the particulars of the breach.

(c) Either party may terminate this Agreement upon written notice to the other party, if: (i) the other party is subject to proceedings in bankruptcy, or insolvency, whether voluntary or involuntary, (ii) a receiver is appointed in respect of all or a substantial portion of the other party's assets; or (iii) the other party assigns its property to its creditors or generally becomes unable to pay its debts as they become due.

Upon any termination of this Agreement, the Consultant shall deliver to Enbridge the results of all Services provided as of the date of termination, including completed or uncompleted deliverables for which payment has been received in accordance with the terms of this Agreement.

5. **Facilities**

Enbridge shall provide to the Consultant use of such office facilities as may be required by the Consultant, acting reasonably, to perform the Services during the Term.

6. **Reimbursement for Expenses**

In addition to the payments to be made pursuant to Section 2 hereof, Enbridge shall reimburse the Consultant for all reasonable expenses properly incurred by the Consultant in connection with the Services provided to Enbridge hereunder and that have been pre-approved by Enbridge in writing, including, without limitation, reasonable travel and other costs and expenses in connection therewith. Such pre-approved reasonable expenses incurred by the Consultant in rendering Services shall be reimbursed by Enbridge net of GST/HST. GST/HST shall be charged, where applicable, by the Consultant on the expenses incurred, net of the input tax credits/reimbursements for GST/HST claimed by the Consultant. Concurrently with its delivery of invoices to Enbridge as contemplated by Section 2 hereof, the Consultant shall submit to Enbridge invoices and statements setting out in reasonable detail the nature and amount of the expenses or costs incurred by the Consultant for which the Consultant claims reimbursement, and Enbridge shall within sixty (60) days of the receipt of such invoices and statements reimburse the Consultant for all approved invoiced expenses and costs. The Consultant shall provide to Enbridge copies of all documentation in support of invoiced expenses as Enbridge may request from time to time during the Term hereof.

7. **Independent Contractor**

Notwithstanding anything to the contrary herein contained, the Consultant shall not, for any purpose, be or be deemed to be an employee of Enbridge during the Term or at any time during which the Services described in Section 1 hereof are provided to Enbridge nor shall anything in this Agreement create or be

construed for any purpose as creating any relationship between Enbridge and the Consultant of employer and employee. Except as expressly provided herein, Enbridge shall not be liable to contribute to any employee benefit or pension plan or pay premiums for any policy or form of insurance whatsoever on behalf of the Consultant nor to pay any amounts or premiums on its behalf in respect of the Canada Pension Plan, Ontario Health Insurance Plan, Workplace Safety and Insurance Board or Employment Insurance, nor to deduct or withhold from source any amount from amounts payable by Enbridge to the Consultant hereunder in respect of any income tax obligation or liability payable by the Consultant to the Canada Revenue Agency. The Consultant agrees to indemnify and hold Enbridge harmless from and against any order, penalty, interest or tax that may be assessed or levied against Enbridge as a result of the failure or delay of the Consultant to file any return or information required to be filed by the Consultant by any law, ordinance or regulation relating to the Services performed by the Consultant herein.

8. **Confidential Information and Personal Information**

(a) For the purposes of this Section 8, the following definitions will apply:

(i) "Confidential Information", means all information pertaining to the business and affairs of Enbridge, its affiliates and subsidiaries, whether oral or written, furnished by Enbridge to the Consultant, its employees and representatives, whether furnished or prepared before or after the date of this Agreement, and includes all analysis, compilations, data, studies, reports or other documents prepared by the Consultant based upon or including any of the information furnished by Enbridge, but does not include information which:

A. is at the time of disclosure or thereafter becomes generally available to the public other than as a result of disclosure by the Consultant or anyone to whom the Consultant transmits the information;

B. is at the time of disclosure or thereafter becomes known or available to the Consultant on a non-confidential basis and not in contravention of applicable law from a source other than Enbridge that is entitled to disclose the information; or

C. is already in the possession of the Consultant or is lawfully acquired, provided that such information is not subject to another confidentiality agreement with, or obligations of secrecy to Enbridge.

(ii) "Person" includes individuals, partnerships, firms and corporations.

(b) Enbridge is furnishing the Confidential Information to the Consultant solely for the purpose of assisting the Consultant in the performance of Services which the Consultant provides to Enbridge. The Consultant shall not use the Confidential Information for any purpose other than the performance of Services provided to Enbridge.

(c) The Consultant acknowledges that the Confidential Information is the property of Enbridge, which is confidential and material to the interests, business and affairs of Enbridge and that disclosure thereof would be detrimental to the interests, business and affairs of Enbridge. Accordingly, the Consultant agrees that it shall maintain the confidentiality of the Confidential Information and that it shall not disclose the Confidential Information to any Person for any reason whatsoever except as expressly provided herein.

(d) The Consultant may disclose Confidential Information to the extent required by a court of competent jurisdiction or other governmental or regulatory authority or otherwise as required by applicable law, provided that the Consultant first give Enbridge prompt written notice (except where the governmental or regulatory authority has expressly ordered that no notice be given) and co-operate with and assist Enbridge in responding to the request or demand for disclosure.

(e) The Consultant acknowledges and agrees that Enbridge would be irreparably harmed if any provision of this Agreement is not performed by the Consultant in accordance with its terms. Accordingly, Enbridge shall be entitled to an injunction or injunctions to prevent breaches of any of the provisions of this Agreement and may specifically enforce such provisions by an action

instituted in a court having jurisdiction. These specific remedies are in addition to any other remedy to which Enbridge may be entitled at law or equity.

(f) If in the course of performing Services hereunder, the Consultant obtains or accesses personal information about an individual, including without limitation, a customer, potential customer or employee or contractor of Enbridge ("Personal Information") the Consultant agrees to treat such Personal Information in compliance with all applicable federal or provincial privacy or protection of personal information laws and to use such Personal Information only for purposes of providing the Services hereunder. Furthermore, the Consultant acknowledges and agrees that it will:

(i) not otherwise copy, retain, use, modify, manipulate, disclose or make available any Personal Information, except as required by applicable law;

(ii) establish or maintain in place appropriate policies and procedures to protect Personal Information from unauthorized collection, use or disclosure;

(iii) implement such policies and procedures thoroughly and effectively;

(iv) except as required for purposes of providing the Services hereunder, will not develop or derive, for any purpose whatsoever, any products in machine-readable form or otherwise, that incorporates, modifies, or uses in any manner whatsoever, any Personal Information; and

(v) upon completion of its Services for or on behalf of Enbridge, will at Enbridge's direction: A. return; or B. destroy all Personal Information and all copies and records thereof in its possession.

9. **Indemnification**

The Consultant hereby agrees to and shall:

(a) be liable to Enbridge and its directors, officers and employees, for all claims, liabilities, damages, costs, losses and expenses whatsoever which Enbridge or any of its directors, officers and employees may suffer, sustain or incur; and

(b) indemnify and save harmless Enbridge, Enbridge's affiliated and subsidiary companies, and their directors, officers, agents, employees and representatives from and against any and all liabilities, claims, demands, damages, loss, costs and expenses (including without limitation all applicable solicitors' fees, court costs and disbursements, investigation expenses, adjusters' fees and disbursements) to or which any third party may suffer, sustain or incur,

in respect of all matters or anything which may arise out of any act or omission directly related to any breach of this Agreement by the Consultant, its employees or representatives save to the extent that such breach was caused or contributed to by Enbridge, Enbridge's affiliated and subsidiary companies, and their directors, officers, agents, employees and representatives. Consultant's assumed liabilities under this Agreement, including its obligation to indemnify the counterparty, are limited to: (i) the amount Consultant has been paid as compensation for services performed under this Agreement, and/or (ii) Consultant's insurance coverage.

10. **Work Product**

(a) For the purposes of this Section 10, "Work Product" shall include any of the following, which are developed in the course of or arise from the Services provided by the Consultant to Enbridge hereunder throughout the Term: (i) any deliverables produced under any schedule to this Agreement together with any and all notes, reports, research information, compilations, data specifications, designs, programs, documentation, software (including object code and source materials), development tools, products and other materials or things; (ii) any and all knowledge, know-how, techniques, inventions, processes, trade secrets, methodologies, approaches and other intangible intellectual property rights; and (iii) all designs, patent applications, issued patents, industrial design registrations, design patents, trade-mark applications, registered trade-marks and copyright which may relate thereto.

(b) For the purposes of this Section 10, "Consultant Materials" comprises any of the following, which were developed by the Consultant, at its own cost and expense in advance of and independent of this Agreement and as proven by the Consultant to be the case in the event of a dispute concerning the same: (i) any and all notes, research, information, data, specifications, designs, programs, documentation, software (including object code and source materials), development tools, products and other materials or things; (ii) any and all knowledge, know-how, techniques, inventions, processes, trade secrets, methodologies, approaches and other intangible intellectual property rights; and (iii) all designs, patent applications, issued patents, industrial design registrations, design patents, trade-mark applications, registered trade-marks and copyright which may relate thereto.

(c) All right, title and interest in and to the Work Product shall be the property of Enbridge. The Consultant shall ensure that any agent or employee of the Consultant shall have waived in writing all of his or her moral rights over any such Intellectual Property. During and after the Term of this Agreement, the Consultant shall from time to time as and when requested by Enbridge execute all papers and documents and perform other acts as necessary or appropriate to evidence or further document Enbridge's ownership of the Work Product and the intellectual property rights therein.

(d) The Consultant retains all right, title and interest in and to the Consultant Materials. The Consultant hereby grants to Enbridge a non-exclusive, perpetual, irrevocable, non-terminable, transferable, assignable and royalty-free license to copy, disclose, use, operate, maintain, repair, modify, enhance, make derivative works, license, sub-license and otherwise commercially exploit without limitation or restriction those Consultant Materials used in connection with the delivery of the Services or to the extent contained within any Work Product.

(e) The Consultant agrees to fully indemnify and hold harmless Enbridge from and against any and all: (i) claims, demands and actions; (ii) liabilities, damages or losses awarded by a court of competent jurisdiction or as agreed to as part of a settlement; and (iii) litigation costs and/or expenses (including reasonable legal fees and disbursements) reasonably incurred by Enbridge in connection with any claim that the Services or Work Product provided hereunder infringe any patent, copyright, trade secret or other right of any third party.

11. **Representations and Warranties**

(a) The Consultant represents, warrants and covenants with Enbridge that: (i) it will perform all Services in a good and workmanlike manner using reasonable care (at a level that is at least consistent with industry standards for the provision of similar services) and in accordance with the terms of this Agreement; (ii) it possesses the knowledge, skill and experience necessary for the provision and completion of the Services in accordance with the terms of this Agreement; and (iii) any deliverables provided hereunder shall conform to their relevant specifications as described in the applicable schedule.

(b) The Consultant agrees that under no circumstances will it interface a non-Enbridge computing device (including without limitation desktops, laptops, handheld device) with the Enbridge intranet or internet without obtaining the prior written approval of Enbridge. To the extent the deliverables produced hereunder involve the provision or development of any software application, interface or electronic data, the Consultant shall use commercially reasonable efforts to prevent the introduction of any virus to the hardware and computer systems upon which the application, interface or electronic data are to be installed. During the Term of this Agreement, the Consultant shall implement and run virus prevention and detection control procedures in accordance with industry standards.

(c) In addition to the policies described in Section 25, the Consultant shall ensure that it is familiar with and understands all of Enbridge's current policies, procedures and standards that are pertinent to the activities associated with the Services and which have been provided to the Consultant in advance of the execution of this Agreement.

(d) If, during the performance of these services or within six months following completion of the assignment, such services shall prove to be faulty or defective by reason of a failure to meet such standards, Consultant agrees that upon prompt written notification from Enbridge prior to the expiration of the six month period following the completion of the assignment containing any such fault or defect, such faulty portion of the services shall be redone at no cost to Enbridge up to a maximum amount equivalent to the cost of the services rendered under this assignment. The foregoing shall constitute Consultant's sole liability with respect to the accuracy or completeness of the work and the activities involved in its preparation.

12. **Subcontractors**

The Consultant shall not enter into any agreement with any other party to assist in the provision of the Services described in Section 1 hereof (hereinafter described as a "Subcontract") nor shall the Consultant allow any other party to perform such Services or any part thereof without first obtaining the consent in writing of Enbridge, which consent may be withheld by Enbridge, acting reasonably. Notwithstanding any approval or consent that may be provided by Enbridge in connection with any Subcontract, the Consultant shall not be relieved of any of its liabilities and responsibilities hereunder. Any party which enters into a Subcontract with the Consultant shall be required by the terms of such Subcontract to comply with and be bound by the obligations and responsibilities of the Consultant described hereunder and without restricting the generality of the foregoing, any Subcontract which has been entered into without the prior written consent of Enbridge shall be null and void and without force and effect.

13. **Insurance**

Save and except where Enbridge specifies otherwise in writing, the Consultant shall at its own expense maintain and keep in full force and effect during the Term hereof and for a period of two (2) years following the expiry of the Term or other termination of this Agreement:

(a) Commercial General Liability insurance having a minimum inclusive coverage limit, including personal injury and property damage, of at least Two Million Dollars ($2,000,000) per occurrence. Enbridge Gas Inc. must be listed as the certificate holder and be added as an additional insured in the insurance policy, which should be extended to cover contractual liability, products/completed operations liability, owners'/ contractors' protective liability and must also contain a cross liability clause;

(b) Automobile Liability insurance on all vehicles used in connection with this Agreement and such insurance shall have a limit of at least One Million Dollars ($1,000,000) in respect of bodily injury (including passenger hazard) and property damage inclusive of any one accident;

(c) Non-Owned Automobile Liability insurance and such insurance shall have a limit of at least One Million Dollars ($1,000,000) in respect of bodily injury (including passenger hazard) and property damage, inclusive in any one accident; and

(d) such other insurance as Enbridge may in its discretion determine to be necessary, including, but not limited to, Professional Liability or Errors and Omissions insurance.

The Consultant shall forthwith after entering into this Agreement, and from time to time thereafter at the request of Enbridge, furnish to Enbridge a memorandum of insurance or an insurance certificate setting out the terms and conditions of each policy of insurance (all such policies of insurance being hereinafter described as the "Insurance Policies") maintained by the Consultant in order to satisfy the requirements of this section. At any time and from time to time at the request of Enbridge, the Consultant shall furnish Enbridge with one or more duly completed insurance certificates in the form requested by Enbridge to evidence the details of all the Insurance Policies. The Insurance Policies shall be arranged with insurers acceptable to Enbridge, acting reasonably, and shall contain such terms and conditions as are reasonably acceptable to Enbridge. The Consultant shall not cancel, terminate or materially alter the terms of any of the Insurance Policies without giving thirty (30) days prior notice in writing to Enbridge. The Consultant shall cause or arrange for any of its insurers under any one or more of the Insurance Policies to oblige itself contractually in writing to Enbridge to provide thirty (30) days prior notice in writing before cancelling, terminating or materially altering the Insurance Policies under which it is an insurer.

14. **Compliance with Laws**

The Consultant agrees to comply with the Occupational Health and Safety Act (Ontario) and the Workplace Safety and Insurance Act (Ontario) and with all other prevailing federal, provincial and municipal laws and regulations or any other laws or regulations in force in any jurisdiction where the Services are performed (the "Laws") and which are applicable to the Consultant, its subcontractors and the Services provided hereunder, and the Consultant shall familiarize itself and procure all required permits and licenses and pay all charges and fees necessary or incidental to the due and lawful prosecution of this Agreement, and maintain all documentation as may be required by the Laws, and shall indemnify and save harmless Enbridge, its directors, officers, agents and employees thereof against any claim or liability from or based on the violation of any Laws, whether by the Consultant, its officers, employees, subcontractors, representatives or agents. The Consultant shall, from time to time, if requested by Enbridge, furnish Enbridge with evidence of such compliance, and in particular: (i) evidence from the Workplace Safety and Insurance Board, or the equivalent thereof in any jurisdiction where the Services provided hereunder are carried out, that the Consultant and any party with which it has entered into a Subcontract are in compliance with and have paid all assessments and other amounts owing pursuant to the workers' compensation legislation of such jurisdiction; and (ii) evidence of the Consultant's compliance with any training requirements under the Laws including, without limitation, the provision of such statements or certificates pertaining to the Consultant's compliance in the form(s) prescribed by Enbridge from time to time.

Enbridge is committed to compliance with the Accessibility for Ontarians with Disabilities Act, 2005, O.Reg. 429/07 and O.Reg. 191/11, the Enbridge Customer Service Policy for Providing Goods and Services to People with Disabilities and the Enbridge Integrated Accessibility Standards Policy (collectively the "AODA"). The Consultant shall ensure that it is in full compliance with all of its obligations under AODA. Without limiting the generality of the foregoing the Consultant shall ensure that all of its employees, agents, volunteers, or others engaged by the Consultant in the delivery of services under this Agreement receive training in connection with the requirements of the AODA. If requested to do so, the Consultant shall provide Enbridge with copies of its policies, practices, procedures, training materials and training records including the dates on when the training is provided, and the names of the individuals trained, and confirmation the Consultant has reported its compliance to the Ministry of Community and Social Services or such other governmental authority as provided in the AODA.

The Consultant will ensure that any personnel it assigns to work in Canada, where they are not a Canadian citizen or Canadian permanent resident of Canada, will obtain and maintain the lawful ability to engage in commercial activities in Canada through the issuance of the appropriate documentation from Canada Border Services Agency and Citizenship and Immigration Canada. The Consultant's personnel where necessary will obtain lawful work permits to engage in business-related activities as temporary foreign workers and will notify Enbridge if any applications for work permits and work permit renewals are refused. The Consultant will not send personnel to any Enbridge-related work site if they do not possess the necessary lawful permission to work in Canada. The Consultant will take full responsibility to secure the necessary documentation and produce such documentation when entering a Canadian work site of Enbridge.

15. **Waiver**

Either the Consultant or Enbridge may, in writing, extend the time for performance by the other and waive non-compliance or non-performance by the other of any of the other's obligations, covenants and agreements under this Agreement and any compliance therewith or performance thereof. However, no such extension or waiver shall operate so as to waive, diminish or reduce the scope of or otherwise affect any obligation, covenant or agreement of such other which is not the subject matter of such extension or waiver or, except to the extent of such extension or waiver, of the obligation, covenant and agreement which is the subject matter of such waiver. No act or failure to act of either the Consultant or Enbridge shall be or be deemed to be an extension or waiver of timely or strict performance by the other of the other's obligations, covenants and agreements under this Agreement except to the extent notice thereof is given to the other.

16. **Notice**

Any notice or other communication to be given under or pursuant to the provisions hereof or in any way concerning this Agreement shall be sufficiently given if reduced to writing and delivered to the person to whom such communication is to be given or sent by facsimile or electronic internet communication, addressed to such person at the address set forth below:

If to Enbridge:

ENBRIDGE GAS INC.
50 Keil Drive North, Box 2001
Chatham ON N7M 5M1
Attention: Danielle Dreveny, Manager Capital FP&A
Phone: 519-436-4600 ext. 5002330
Email: Danielle.Dreveny@enbridge.com

With a copy to: Law Department
Email: EGILawContracts@enbridge.com

If to the Consultant:

CONCENTRIC ADVISORS ULC
200 Rivercrest Drive S. E.
Calgary Alberta T2C 2X5
Attention: Larry Kennedy, Senior Vice President
Phone: 587-997-6489 Ext.
Email: lkennedy@ceadvisors.com

or at such other address as may be specified therefor by proper notice hereunder. A notice or communication shall be deemed to have been sent and received on the day it is delivered personally or by courier or by facsimile or by electronic internet communication. If such day is not a business day or if the notice or communication is received after 5:00 PM (at the place of receipt) on any business day, the notice or communication shall be deemed to have been sent and received on the immediately following business day.

17. **Interpretation**

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. Headings used herein are for the convenience of reference only and shall not be considered in construing or interpreting this Agreement. The words "herein", "hereunder", "hereof" and other similar words refer to this Agreement as a whole and not to any particular paragraph. Any provision herein prohibited by law shall to the extent prohibited be ineffective without invalidating any other provisions hereof. All references to amounts of money in this Agreement and any schedule shall mean lawful currency of Canada.

18. **Assignment**

The Consultant may not assign this Agreement in whole or in part without the express prior consent in writing of Enbridge. This Agreement shall be binding upon and enure to the benefit of the successors and assigns of Enbridge.

19. **Use of Enbridge Name and Logo**

The Consultant shall not use or display Enbridge's name or any symbols, signs, trademarks and other marks denoting and identifying Enbridge in any manner whatsoever without the prior written authorization of Enbridge. Consultant may refer to the following information in materials used to promote its services: (i) a general description of the nature and scope of the services performed, and (ii) the time period of the engagement.

20. **Time of Essence**

Time shall be of the essence in the performance of the Services.

21. **Survival**

All warranties and indemnities contained in this Agreement, and the obligations contained in Section 8, shall survive the termination of this Agreement irrespective of the time of or party responsible for such termination, and such warranties, indemnities and obligations shall remain in full force and effect and be binding on the Contractor notwithstanding such termination.

22. **Further Assurances**

Each of the parties shall, from the time of the written request of the other party, do all such further acts and execute and deliver or cause to be done, executed or delivered all such further acts, deeds, documents, assurances and things as may be required, acting reasonably, in order to fully perform and to more effectively implement and carry out the terms of this Agreement.

23. **Entire Agreement**

This Agreement, including any schedules attached hereto, constitutes the entire agreement between the parties with respect to the subject matter set out herein and replaces any prior understandings or agreements, whether written or oral, regarding such subject matter. No change or modification of this Agreement is valid unless it is in writing and signed by both parties. No disclaimers, purchase order documents, invoices or other documents of the Consultant shall be binding upon Enbridge.

24. **Audit**

The Consultant shall, following no less than seven (7) business days advance notice in writing, provide to such auditors (including external auditors and Enbridge's internal audit staff or agents) as Enbridge may designate in writing, supervised access to the data, records and supporting documentation maintained by the Consultant with respect to the Services solely for the purpose of: (i) performing audits and inspections to enable Enbridge to satisfy applicable regulatory requirements or certify compliance with applicable laws; and (ii) to confirm that the Services are being provided in accordance with the terms of this Agreement. Enbridge and its auditors shall use commercially reasonable efforts to conduct such audits in a manner that will result in a minimum of inconvenience and disruption to the Consultant's business operations. In the event that if any such audit reveals any: (a) errors or deficiencies in the completion of the Services or invoicing of the Services; or (b) overpayments to the Consultant by Enbridge, then the Consultant shall forthwith correct such errors or deficiencies, including if applicable refunding any overpayment to Enbridge. The Consultant shall retain all records for three (3) years from the date of expiration or earlier termination of this Agreement, or such longer period as Enbridge may require having regard to the nature of the Services. Enbridge and its auditors may not have access to information deem proprietary, trade secret, and/or confidential by the Consultant.

25. **Enbridge Policies**

The Consultant acknowledges receipt of a copy of each of Enbridge Inc.'s Statement on Business Conduct for Enbridge Inc. and its Subsidiaries and Lifesaving Rules, each as amended from time to time (the "Policies"). The Consultant agrees to comply with the Policies in connection with its delivery of the Services described in this Agreement, and agrees that, if requested by Enbridge, it will ensure all personnel delivering the Services herein attend training on the Lifesaving Rules.

26. **ISNetworld Requirement**

If required by Enbridge, the Consultant shall subscribe with ISN Software Corporation as a registrant of ISNetworld ("ISN") or any successor service mandated by Enbridge from time to time, and maintain a performance grading within ISN that is acceptable to Enbridge (the "ISNetworld Requirement") and shall: (a) provide all records and information as required by ISN or Enbridge, including, but not limited to, training and qualification data of the Consultant personnel, including subcontractors and employees, relating to the Services; and (b) maintain compliance with the ISNetworld Requirement during the currency of this Agreement.

[remainder of page intentionally left blank]

27. **Counterparts and Execution**

This Agreement may be executed by the parties in separate counterparts, each of which when so executed and delivered will be deemed to be an original, and all such counterparts will together constitute one and the same instrument. Delivery of a signature by electronic transmission or by facsimile transmission, including by email delivery of a "portable document format" ("pdf") document, shall create a valid and binding obligation. This Agreement may be executed using electronic signatures.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first written above.

CONCENTRIC ADVISORS ULC

By:
Name: Larry Kennedy
Title: Senior Vice President.

By:
Name:
Title:
(Please print name and title of Signing Officer)

Witness:
Name:

(Witness required if Contractor is a Sole Proprietor)

ENBRIDGE GAS INC.

By: Colin Healey
Colin Healey (May 7, 2021 16:04 MDT)
Name: Colin Healey
Title: Director FP&A GDS

By:
Name:
Title:

SCHEDULE A

TO THE CONSULTING AGREEMENT BETWEEN ENBRIDGE GAS INC. AND CONCENTRIC ADVISORS ULC Dated April 9, 2021

This Schedule is made under the above referenced consulting agreement (the "Agreement") between ENBRIDGE GAS INC. ("Enbridge") and CONCENTRIC ADVISORS ULC (the "Consultant").

1. **SCOPE OF SERVICES**

The Consultant will undertake the following Services:

1. Determine methodologies for depreciation and the estimation of net salvage, including:
a. Performing research to identify applicable methodologies
b. Assessing the methodologies identified with consideration to a base case and alternative scenarios including energy transition
c. Recommending appropriate methodologies
2. Perform a service life study which will include the following tasks:
a. A full review of plant accounting data and plant balances as of EGI's 2020 fiscal year-end
b. Inclusion of the forecast 2022-2023 capital program related to capital additions and retirements into the databases used for the review of average service life and depreciation rate calculations
c. A physical field review of facilities (if necessary)
d. Interviews with EGI management and internal subject matter experts
e. Development of a detailed peer comparison analysis
3. Determine the adequacy of the current accumulated depreciation accounts to reflect the consumption of the consumed service value of the EGI plant in service
4. Determine the appropriate net salvage percentages and assess the adequacy of the current balance of net salvage recoveries
5. Determine appropriate discount rates to be used in analyses and perform sensitivity analysis as required
6. Deliver a full and comprehensive draft report by November 30th, 2021; management meetings to discuss the depreciation policies and results of the depreciation study
7. Review the actual 2021 plant accounting activity immediately following the close of the 2021 financial ledgers to determine if any changes are required to the draft depreciation study report
8. Deliver a final report, in format suitable to be presented as evidence before the OEB by February 11, 2022

2. **DELIVERABLES**

The Consultant will provide the following deliverables:

A written report that provides descriptions and outcomes of the analyses of depreciation and net salvage estimation methods under various scenarios, service lives, net salvage values, and summaries and detailed tabulations of annual and accrued depreciation. The consultant may need to participate in the OEB proceeding as an expert witness – either through written submissions or in person.

3. **TERM AND COMMENCEMENT AND COMPLETION DATES**

This Schedule shall be effective as of April 9, 2021 and expire December 31, 2023, or such other date as the parties may mutually agree in writing.

4. **KEY PERSONNEL**

The Consultant will provide the following personnel to deliver the services set out above under Scope of Services:

Larry Kennedy, Senior Vice President
Amanda Nori, Project Manager

Colin Burns, Consultant
Javier Sola, Consultant

5. **FEES AND PAYMENT TERMS**

Fees: Consultant to conduct the study for a lump sum price of [redacted] Consultant shall conduct any post filing work at their standard rates which are attached to this Contract. These rates will increase annually at a rate to be determined, but not exceeding 2% per year. Consultant will communicate any rate increases to Enbridge as soon as they are approved.

Expenses: N/A

The above fees and expenses cannot be exceeded without prior written approval from Enbridge.

Fees are payable by Enbridge within sixty (60) days of receipt from the Consultant of an appropriate invoice setting out in reasonable detail the nature of the services provided.

[Remainder of page intentionally left blank; signature page to follow]

Dated as of April 9, 2021.

CONCENTRIC ADVISORS ULC

By: ______________________
Name: Larry Kennedy
Title: Senior Vice President

By: ______________________
Name:
Title:
(Please print name and title of Signing Officer)

Witness: ______________________
Name:

(Witness required if Contractor is a Sole Proprietor)

ENBRIDGE GAS INC.

By: Colin Healey
Colin Healey (May 7, 2021 16:04 MDT)
Name: Colin Healey
Title: Director FP&A GDS

By: ______________________
Name: • •
Title: •

Rates for O.E.B. filing and proceedings

		Hourly Rates in CDN $		
		2021	2022	2023
Role Description	**Estimated Number of Hours**	[redacted]	[redacted]	[redacted]
Senior Vice President	52	[redacted]	unknown	
Project Manager	114	[redacted]		
Senior Consultant	161	[redacted]		
Consultant		[redacted]		
Analyst	68	[redacted]		

ENBRIDGE

500 Consumers Rd
North York ON M2J 1P8

Lesley Austin, Advisor Regulatory
Tel: 416-495-6505
Email: lesley.austin@enbridge.com

June 28, 2021

CONCENTRIC ENERGY ADVISORS, INC.
293 Boston Post Road West, Ste 500
Malborough Massachusetts 01752

Dear Sir / Madam,

RE: Consulting Agreement with Enbridge Gas Inc.

Attached please find for signature our Consulting Agreement. Kindly arrange to have the Agreement and the attached Schedule signed. Please ensure you read and understand all of the terms and conditions of the Agreement, as well as the enclosed Statement on Business Conduct and Lifesaving Rules.

We will also require the following:

- A current clearance certificate or letter of exemption from the Ontario Workplace Safety and Insurance Board ("WSIB"). If your employees are in a jurisdiction other than Ontario, please provide equivalent proof of coverage, and new proof of coverage must be filed with us upon expiry/renewal of such proof of coverage.

Please return the applicable WSIB document noted above, together with a signed copy of the Consulting Agreement and a signed copy of the Schedule, promptly following receipt of this letter. Upon receipt of all the documents in our office, we will execute the Agreement and a PDF copy of the Agreement will be returned to you for your records.

If you have any questions, please contact me at the above-noted telephone number.

Sincerely,

Lesley Austin
Advisor Regulatory

Encls.

CONSULTING AGREEMENT

THIS AGREEMENT made effective June 14, 2021.

B E T W E E N:

ENBRIDGE GAS INC.
("Enbridge")

- and -

CONCENTRIC ENERGY ADVISORS, INC.
(the "Consultant")

WITNESSES THAT in consideration of the mutual covenants and agreements herein contained, the parties hereto covenant and agree as follows:

1. **Scope of Services**

   (a) During the term hereof (as hereinafter defined), the Consultant shall provide consulting services (the "Services") to Enbridge, on the terms and conditions set forth below.

   (b) The scope of work for specific projects to be undertaken by the Consultant at the request of Enbridge will be described in separate schedules and/or service/purchase orders (each a "schedule") referencing this Agreement, each of which shall become effective, be incorporated by reference and form an integral part of this Agreement upon the execution or acknowledgement of each such schedule by Enbridge and the Consultant. The schedule for each project may specify the names of key individuals, scope of Services, deliverables, commencement and completion dates, rate of compensation and payment terms applicable to such project. Each schedule described above shall be prepared using a form similar to the attached Schedule "A" or other forms as provided by Enbridge from time to time.

2. **Compensation**

In consideration of the Services and deliverables to be provided by the Consultant hereunder, and provided that the Consultant is not in default of its obligations hereunder, Enbridge shall remit to the Consultant all amounts required to be paid in accordance with the applicable schedule.

Consultant shall be responsible for charging, collecting and remitting all applicable federal and provincial sales, use and value-added taxes in respect of the fees paid or payable to Consultant and, in particular, the goods and services tax ("GST") and harmonized sales tax ("HST") imposed under Part IX of the Excise Tax Act (the "ETA"), the Quebec sales tax ("QST") imposed under an Act respecting the Quebec Sales Tax (the "QSTA") and any provincial sales taxes ("PST"); and such taxes, if applicable, shall be shown separately on all invoices. Where Consultant is required to collect any GST/HST, QST or similar tax, Consultant shall provide Enbridge with the documentary evidence as prescribed pursuant to the ETA or QSTA, any successor provision thereto or any similar provision of any other taxing statute as is required to entitle Enbridge to claim an input tax credit, input tax refund, rebate, refund or any other form of relief in respect of such taxes.

Where the Consultant is a non-resident of Canada for purposes of the Income Tax Act (Canada) (the "ITA"), with respect to the invoice or statement of Fees issued pursuant to any schedule, the Consultant will identify the location where the Services are provided, separate Services performed in Canada from Services performed outside of Canada, identify the number of days Services were performed in Canada (including travel days to/from Canada) and, for Services performed in Canada, identify the physical location, indicating city and province, where such Services were performed. Where the non-resident

Consultant has not obtained and provided to Enbridge a non-resident withholding tax waiver at such time as Enbridge makes any payment to the Consultant for Services, Enbridge shall withhold such percentage of any payment as mandated under the ITA with respect to the Services provided in Canada or on the full invoice or statement amount where the Consultant has not clearly separated the Services performed in Canada from Services performed outside of Canada. Enbridge shall remit the withheld amount to Canada Revenue Agency, or its successor, in the manner and at the time required by the ITA. For further clarification, it is the Consultant's responsibility to obtain the tax waiver, if available. In the event that Enbridge is assessed for any non-resident withholding taxes payable, the Consultant agrees to forthwith reimburse Enbridge for such amount together with applicable interest and penalties, if any.

3. **Term**

Subject to earlier termination as provided for herein, the term of this Agreement shall commence on the day set forth above and expire on December 31, 2023 (hereinafter the "Term").

4. **Termination**

(a) Enbridge may terminate this Agreement or any schedule to this Agreement for convenience upon giving two (2) weeks written notice to the Consultant.

(b) Either party may terminate this Agreement in case of a breach by the other party of its obligations hereunder, provided that the breach is not cured within five (5) days of written notification by the non-defaulting party to the defaulting party setting out the particulars of the breach.

(c) Either party may terminate this Agreement upon written notice to the other party, if: (i) the other party is subject to proceedings in bankruptcy, or insolvency, whether voluntary or involuntary, (ii) a receiver is appointed in respect of all or a substantial portion of the other party's assets; or (iii) the other party assigns its property to its creditors or generally becomes unable to pay its debts as they become due.

Upon any termination of this Agreement, the Consultant shall deliver to Enbridge the results of all Services provided as of the date of termination, including completed or uncompleted deliverables for which payment has been received in accordance with the terms of this Agreement.

5. **Facilities**

Enbridge shall provide to the Consultant use of such office facilities as may be required by the Consultant, acting reasonably, to perform the Services during the Term.

6. **Reimbursement for Expenses**

In addition to the payments to be made pursuant to Section 2 hereof, Enbridge shall reimburse the Consultant for all reasonable expenses properly incurred by the Consultant in connection with the Services provided to Enbridge hereunder and that have been pre-approved by Enbridge in writing, including, without limitation, reasonable travel and other costs and expenses in connection therewith. Such pre-approved reasonable expenses incurred by the Consultant in rendering Services shall be reimbursed by Enbridge net of GST/HST. GST/HST shall be charged, where applicable, by the Consultant on the expenses incurred, net of the input tax credits/reimbursements for GST/HST claimed by the Consultant. Concurrently with its delivery of invoices to Enbridge as contemplated by Section 2 hereof, the Consultant shall submit to Enbridge invoices and statements setting out in reasonable detail the nature and amount of the expenses or costs incurred by the Consultant for which the Consultant claims reimbursement, and Enbridge shall within sixty (60) days of the receipt of such invoices and statements reimburse the Consultant for all approved invoiced expenses and costs. The Consultant shall provide to Enbridge copies of all documentation in support of invoiced expenses as Enbridge may request from time to time during the Term hereof.

7. **Independent Contractor**

Notwithstanding anything to the contrary herein contained, the Consultant shall not, for any purpose, be or be deemed to be an employee of Enbridge during the Term or at any time during which the Services described in Section 1 hereof are provided to Enbridge nor shall anything in this Agreement create or be construed for any purpose as creating any relationship between Enbridge and the Consultant of employer and employee. Except as expressly provided herein, Enbridge shall not be liable to contribute to any employee benefit or pension plan or pay premiums for any policy or form of insurance whatsoever on behalf of the Consultant nor to pay any amounts or premiums on its behalf in respect of the Canada Pension Plan, Ontario Health Insurance Plan, Workplace Safety and Insurance Board or Employment Insurance, nor to deduct or withhold from source any amount from amounts payable by Enbridge to the Consultant hereunder in respect of any income tax obligation or liability payable by the Consultant to the Canada Revenue Agency. The Consultant agrees to indemnify and hold Enbridge harmless from and against any order, penalty, interest or tax that may be assessed or levied against Enbridge as a result of the failure or delay of the Consultant to file any return or information required to be filed by the Consultant by any law, ordinance or regulation relating to the Services performed by the Consultant herein.

8. **Confidential Information and Personal Information**

(a) For the purposes of this Section 8, the following definitions will apply:

(i) "Confidential Information", means all information pertaining to the business and affairs of Enbridge, its affiliates and subsidiaries, whether oral or written, furnished by Enbridge to the Consultant, its employees and representatives, whether furnished or prepared before or after the date of this Agreement, and includes all analysis, compilations, data, studies, reports or other documents prepared by the Consultant based upon or including any of the information furnished by Enbridge, but does not include information which:

A. is at the time of disclosure or thereafter becomes generally available to the public other than as a result of disclosure by the Consultant or anyone to whom the Consultant transmits the information;

B. is at the time of disclosure or thereafter becomes known or available to the Consultant on a non-confidential basis and not in contravention of applicable law from a source other than Enbridge that is entitled to disclose the information; or

C. is already in the possession of the Consultant or is lawfully acquired, provided that such information is not subject to another confidentiality agreement with, or obligations of secrecy to Enbridge.

(ii) "Person" includes individuals, partnerships, firms and corporations.

(b) Enbridge is furnishing the Confidential Information to the Consultant solely for the purpose of assisting the Consultant in the performance of Services which the Consultant provides to Enbridge. The Consultant shall not use the Confidential Information for any purpose other than the performance of Services provided to Enbridge.

(c) The Consultant acknowledges that the Confidential Information is the property of Enbridge, which is confidential and material to the interests, business and affairs of Enbridge and that disclosure thereof would be detrimental to the interests, business and affairs of Enbridge. Accordingly, the Consultant agrees that it shall maintain the confidentiality of the Confidential Information and that it shall not disclose the Confidential Information to any Person for any reason whatsoever except as expressly provided herein.

(d) The Consultant may disclose Confidential Information to the extent required by a court of competent jurisdiction or other governmental or regulatory authority or otherwise as required by applicable law, provided that the Consultant first give Enbridge prompt written notice (except where the governmental or regulatory authority has expressly ordered that no notice be given) and co-operate with and assist Enbridge in responding to the request or demand for disclosure.

(e) The Consultant acknowledges and agrees that Enbridge would be irreparably harmed if any provision of this Agreement is not performed by the Consultant in accordance with its terms. Accordingly, Enbridge shall be entitled to an injunction or injunctions to prevent breaches of any of the provisions of this Agreement and may specifically enforce such provisions by an action instituted in a court having jurisdiction. These specific remedies are in addition to any other remedy to which Enbridge may be entitled at law or equity.

(f) If in the course of performing Services hereunder, the Consultant obtains or accesses personal information about an individual, including without limitation, a customer, potential customer or employee or contractor of Enbridge ("Personal Information") the Consultant agrees to treat such Personal Information in compliance with all applicable federal or provincial privacy or protection of personal information laws and to use such Personal Information only for purposes of providing the Services hereunder. Furthermore, the Consultant acknowledges and agrees that it will:

(i) not otherwise copy, retain, use, modify, manipulate, disclose or make available any Personal Information, except as required by applicable law;

(ii) establish or maintain in place appropriate policies and procedures to protect Personal Information from unauthorized collection, use or disclosure;

(iii) implement such policies and procedures thoroughly and effectively;

(iv) except as required for purposes of providing the Services hereunder, will not develop or derive, for any purpose whatsoever, any products in machine-readable form or otherwise, that incorporates, modifies, or uses in any manner whatsoever, any Personal Information; and

(v) upon completion of its Services for or on behalf of Enbridge, will at Enbridge's direction: A. return; or B. destroy all Personal Information and all copies and records thereof in its possession.

9. **Indemnification**

The Consultant hereby agrees to and shall:

(a) be liable to Enbridge and its directors, officers and employees, for all claims, liabilities, damages, costs, losses and expenses whatsoever which Enbridge or any of its directors, officers and employees may suffer, sustain or incur; and

(b) indemnify and save harmless Enbridge, Enbridge's affiliated and subsidiary companies, and their directors, officers, agents, employees and representatives from and against any and all liabilities, claims, demands, damages, loss, costs and expenses (including without limitation all applicable solicitors' fees, court costs and disbursements, investigation expenses, adjusters' fees and disbursements) to or which any third party may suffer, sustain or incur,

in respect of all matters or anything which may arise out of any act or omission directly related to any breach of this Agreement by the Consultant, its employees or representatives save to the extent that such breach was caused or contributed to by Enbridge, Enbridge's affiliated and subsidiary companies, and their directors, officers, agents, employees and representatives. Consultant's assumed liabilities under this Agreement, including its obligation to indemnify the counterparty, are limited to: (i) the amount Consultant has been paid as compensation for services performed under this Agreement, and/or (ii) Consultant's insurance coverage.

10. **Work Product**

(a) For the purposes of this Section 10, "Work Product" shall include any of the following, which are developed in the course of or arise from the Services provided by the Consultant to Enbridge hereunder throughout the Term: (i) any deliverables produced under any schedule to this Agreement together with any and all notes, reports, research information, compilations, data specifications, designs, programs, documentation, software (including object code and source materials), development tools, products and other materials or things; (ii) any and all knowledge, know-how, techniques, inventions, processes, trade secrets, methodologies, approaches and other intangible intellectual property rights; and (iii) all designs, patent applications, issued patents, industrial design registrations, design patents, trade-mark applications, registered trade-marks and copyright which may relate thereto.

(b) For the purposes of this Section 10, "Consultant Materials" comprises any of the following, which were developed by the Consultant, at its own cost and expense in advance of and independent of this Agreement and as proven by the Consultant to be the case in the event of a dispute concerning the same: (i) any and all notes, research, information, data, specifications, designs, programs, documentation, software (including object code and source materials), development tools, products and other materials or things; (ii) any and all knowledge, know-how, techniques, inventions, processes, trade secrets, methodologies, approaches and other intangible intellectual property rights; and (iii) all designs, patent applications, issued patents, industrial design registrations, design patents, trade-mark applications, registered trade-marks and copyright which may relate thereto.

(c) All right, title and interest in and to the Work Product shall be the property of Enbridge. The Consultant shall ensure that any agent or employee of the Consultant shall have waived in writing all of his or her moral rights over any such Intellectual Property. During and after the Term of this Agreement, the Consultant shall from time to time as and when requested by Enbridge execute all papers and documents and perform other acts as necessary or appropriate to evidence or further document Enbridge's ownership of the Work Product and the intellectual property rights therein.

(d) The Consultant retains all right, title and interest in and to the Consultant Materials. The Consultant hereby grants to Enbridge a non-exclusive, perpetual, irrevocable, non-terminable, transferable, assignable and royalty-free license to copy, disclose, use, operate, maintain, repair, modify, enhance, make derivative works, license, sub-license and otherwise commercially exploit without limitation or restriction those Consultant Materials used in connection with the delivery of the Services or to the extent contained within any Work Product.

(e) The Consultant agrees to fully indemnify and hold harmless Enbridge from and against any and all: (i) claims, demands and actions; (ii) liabilities, damages or losses awarded by a court of competent jurisdiction or as agreed to as part of a settlement; and (iii) litigation costs and/or expenses (including reasonable legal fees and disbursements) reasonably incurred by Enbridge in connection with any claim that the Services or Work Product provided hereunder infringe any patent, copyright, trade secret or other right of any third party.

11. **Representations and Warranties**

(a) The Consultant represents, warrants and covenants with Enbridge that: (i) it will perform all Services in a good and workmanlike manner using reasonable care (at a level that is at least consistent with industry standards for the provision of similar services) and in accordance with the terms of this Agreement; (ii) it possesses the knowledge, skill and experience necessary for the provision and completion of the Services in accordance with the terms of this Agreement; and (iii) any deliverables provided hereunder shall conform to their relevant specifications as described in the applicable schedule.

(b) The Consultant agrees that under no circumstances will it interface a non-Enbridge computing device (including without limitation desktops, laptops, handheld device) with the Enbridge intranet or internet without obtaining the prior written approval of Enbridge. To the extent the deliverables produced hereunder involve the provision or development of any software application, interface or electronic data, the Consultant shall use commercially reasonable efforts to prevent the introduction of any virus to the hardware and computer systems upon which the application, interface or electronic data are to be installed. During the Term of this Agreement, the Consultant shall implement and run virus prevention and detection control procedures in accordance with industry standards.

(c) In addition to the policies described in Section 25, the Consultant shall ensure that it is familiar with and understands all of Enbridge's current policies, procedures and standards that are pertinent to the activities associated with the Services and which have been provided to the Consultant in advance of the execution of this Agreement.

(d) If, during the performance of these services or within six months following completion of the assignment, such services shall prove to be faulty or defective by reason of a failure to meet such standards, Consultant agrees that upon prompt written notification from Enbridge prior to the expiration of the six month period following the completion of the assignment containing any such fault or defect, such faulty portion of the services shall be redone at no cost to Enbridge up to a maximum amount equivalent to the cost of the services rendered under this assignment. The foregoing shall constitute Consultant's sole liability with respect to the accuracy or completeness of the work and the activities involved in its preparation.

12. **Subcontractors**

The Consultant shall not enter into any agreement with any other party to assist in the provision of the Services described in Section 1 hereof (hereinafter described as a "Subcontract") nor shall the Consultant allow any other party to perform such Services or any part thereof without first obtaining the consent in writing of Enbridge, which consent may be withheld by Enbridge, acting reasonably. Notwithstanding any approval or consent that may be provided by Enbridge in connection with any Subcontract, the Consultant shall not be relieved of any of its liabilities and responsibilities hereunder. Any party which enters into a Subcontract with the Consultant shall be required by the terms of such Subcontract to comply with and be bound by the obligations and responsibilities of the Consultant described hereunder and without restricting the generality of the foregoing, any Subcontract which has been entered into without the prior written consent of Enbridge shall be null and void and without force and effect.

13. **Insurance**

Save and except where Enbridge specifies otherwise in writing, the Consultant shall at its own expense maintain and keep in full force and effect during the Term hereof and for a period of two (2) years following the expiry of the Term or other termination of this Agreement:

(a) Commercial General Liability insurance having a minimum inclusive coverage limit, including personal injury and property damage, of at least Two Million Dollars ($2,000,000) per occurrence. Enbridge Gas Inc. must be listed as the certificate holder and be added as an additional insured in the insurance policy, which should be extended to cover contractual liability, products/completed operations liability, owners'/ contractors' protective liability and must also contain a cross liability clause;

(b) Automobile Liability insurance on all vehicles used in connection with this Agreement and such insurance shall have a limit of at least One Million Dollars ($1,000,000) in respect of bodily injury (including passenger hazard) and property damage inclusive of any one accident;

(c) Non-Owned Automobile Liability insurance and such insurance shall have a limit of at least One Million Dollars ($1,000,000) in respect of bodily injury (including passenger hazard) and property damage, inclusive in any one accident; and

(d) such other insurance as Enbridge may in its discretion determine to be necessary, including, but not limited to, Professional Liability or Errors and Omissions insurance.

The Consultant shall forthwith after entering into this Agreement, and from time to time thereafter at the request of Enbridge, furnish to Enbridge a memorandum of insurance or an insurance certificate setting out the terms and conditions of each policy of insurance (all such policies of insurance being hereinafter described as the "Insurance Policies") maintained by the Consultant in order to satisfy the requirements of this section. At any time and from time to time at the request of Enbridge, the Consultant shall furnish Enbridge with one or more duly completed insurance certificates in the form requested by Enbridge to evidence the details of all the Insurance Policies. The Insurance Policies shall be arranged with insurers acceptable to Enbridge, acting reasonably, and shall contain such terms and conditions as are reasonably acceptable to Enbridge. The Consultant shall not cancel, terminate or materially alter the terms of any of the Insurance Policies without giving thirty (30) days prior notice in writing to Enbridge. The Consultant shall cause or arrange for any of its insurers under any one or more of the Insurance Policies to oblige itself contractually in writing to Enbridge to provide thirty (30) days prior notice in writing before cancelling, terminating or materially altering the Insurance Policies under which it is an insurer.

14. **Compliance with Laws**

The Consultant agrees to comply with the Occupational Health and Safety Act (Ontario) and the Workplace Safety and Insurance Act (Ontario) and with all other prevailing federal, provincial and municipal laws and regulations or any other laws or regulations in force in any jurisdiction where the Services are performed (the "Laws") and which are applicable to the Consultant, its subcontractors and the Services provided hereunder, and the Consultant shall familiarize itself and procure all required permits and licenses and pay all charges and fees necessary or incidental to the due and lawful prosecution of this Agreement, and maintain all documentation as may be required by the Laws, and shall indemnify and save harmless Enbridge, its directors, officers, agents and employees thereof against any claim or liability from or based on the violation of any Laws, whether by the Consultant, its officers, employees, subcontractors, representatives or agents. The Consultant shall, from time to time, if requested by Enbridge, furnish Enbridge with evidence of such compliance, and in particular: (i) evidence from the Workplace Safety and Insurance Board, or the equivalent thereof in any jurisdiction where the Services provided hereunder are carried out, that the Consultant and any party with which it has entered into a Subcontract are in compliance with and have paid all assessments and other amounts owing pursuant to the workers' compensation legislation of such jurisdiction; and (ii) evidence of the Consultant's compliance with any training requirements under the Laws including, without limitation, the provision of such statements or certificates pertaining to the Consultant's compliance in the form(s) prescribed by Enbridge from time to time.

Enbridge is committed to compliance with the Accessibility for Ontarians with Disabilities Act, 2005, O.Reg. 429/07 and O.Reg. 191/11, the Enbridge Customer Service Policy for Providing Goods and Services to People with Disabilities and the Enbridge Integrated Accessibility Standards Policy (collectively the "AODA"). The Consultant shall ensure that it is in full compliance with all of its obligations under AODA. Without limiting the generality of the foregoing the Consultant shall ensure that all of its employees, agents, volunteers, or others engaged by the Consultant in the delivery of services under this Agreement receive training in connection with the requirements of the AODA. If requested to do so, the Consultant shall provide Enbridge with copies of its policies, practices, procedures, training materials and training records including the dates on when the training is provided, and the names of the individuals trained, and confirmation the Consultant has reported its compliance to the Ministry of Community and Social Services or such other governmental authority as provided in the AODA.

The Consultant will ensure that any personnel it assigns to work in Canada, where they are not a Canadian citizen or Canadian permanent resident of Canada, will obtain and maintain the lawful ability to engage in commercial activities in Canada through the issuance of the appropriate documentation from Canada Border Services Agency and Citizenship and Immigration Canada. The Consultant's personnel where necessary will obtain lawful work permits to engage in business-related activities as temporary foreign workers and will notify Enbridge if any applications for work permits and work permit renewals are refused. The Consultant will not send personnel to any Enbridge-related work site if they do not possess the necessary lawful permission to work in Canada. The Consultant will take full responsibility to secure the necessary documentation and produce such documentation when entering a Canadian work site of Enbridge.

15. **Waiver**

Either the Consultant or Enbridge may, in writing, extend the time for performance by the other and waive non-compliance or non-performance by the other of any of the other's obligations, covenants and agreements under this Agreement and any compliance therewith or performance thereof. However, no such extension or waiver shall operate so as to waive, diminish or reduce the scope of or otherwise affect any obligation, covenant or agreement of such other which is not the subject matter of such extension or waiver or, except to the extent of such extension or waiver, of the obligation, covenant and agreement which is the subject matter of such waiver. No act or failure to act of either the Consultant or Enbridge shall be or be deemed to be an extension or waiver of timely or strict performance by the other of the other's obligations, covenants and agreements under this Agreement except to the extent notice thereof is given to the other.

16. **Notice**

Any notice or other communication to be given under or pursuant to the provisions hereof or in any way concerning this Agreement shall be sufficiently given if reduced to writing and delivered to the person to whom such communication is to be given or sent by electronic internet communication, addressed to such person at the address set forth below:

If to Enbridge:

ENBRIDGE GAS INC.
500 Consumers Rd
North York ON M2J 1P8
Attention: Lesley Austin, Advisor Regulatory
Phone: 416-495-6505
Email: lesley.austin@enbridge.com

With a copy to: Law Department
Email: egilawcontracts@enbridge.com

If to the Consultant:

CONCENTRIC ENERGY ADVISORS, INC.
293 Boston Post Road West, Ste 500
Malborough Massachusetts 01752
Attention: Jill Barrile, Project Assistant
Phone: 508-263-6218 Ext.
Email: jbarrile@ceadvisors.com

or at such other address as may be specified therefor by proper notice hereunder. A notice or communication shall be deemed to have been sent and received on the day it is delivered personally or by courier or by electronic internet communication. If such day is not a business day or if the notice or communication is received after 5:00 PM (at the place of receipt) on any business day, the notice or communication shall be deemed to have been sent and received on the immediately following business day.

17. **Interpretation**

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. Headings used herein are for the convenience of reference only and shall not be considered in construing or interpreting this Agreement. The words "herein", "hereunder", "hereof" and other similar words refer to this Agreement as a whole and not to any particular paragraph. Any provision herein prohibited by law shall to the extent prohibited be ineffective without invalidating any other provisions hereof. All references to amounts of money in this Agreement and any schedule shall mean lawful currency of Canada.

18. **Assignment**

The Consultant may not assign this Agreement in whole or in part without the express prior consent in writing of Enbridge. This Agreement shall be binding upon and enure to the benefit of the successors and assigns of Enbridge.

19. **Use of Enbridge Name and Logo**

The Consultant shall not use or display Enbridge's name or any symbols, signs, trademarks and other marks denoting and identifying Enbridge in any manner whatsoever without the prior written authorization of Enbridge. Consultant may refer to the following information in materials used to promote its services: (i) a general description of the nature and scope of the services performed, and (ii) the time period of the engagement.

20. **Time of Essence**

Time shall be of the essence in the performance of the Services.

21. **Survival**

All warranties and indemnities contained in this Agreement, and the obligations contained in Section 8, shall survive the termination of this Agreement irrespective of the time of or party responsible for such termination, and such warranties, indemnities and obligations shall remain in full force and effect and be binding on the Contractor notwithstanding such termination.

22. **Further Assurances**

Each of the parties shall, from the time of the written request of the other party, do all such further acts and execute and deliver or cause to be done, executed or delivered all such further acts, deeds, documents, assurances and things as may be required, acting reasonably, in order to fully perform and to more effectively implement and carry out the terms of this Agreement.

23. **Entire Agreement**

This Agreement, including any schedules attached hereto, constitutes the entire agreement between the parties with respect to the subject matter set out herein and replaces any prior understandings or agreements, whether written or oral, regarding such subject matter. No change or modification of this Agreement is valid unless it is in writing and signed by both parties. No disclaimers, purchase order documents, invoices or other documents of the Consultant shall be binding upon Enbridge.

24. **Audit**

The Consultant shall, following no less than seven (7) business days advance notice in writing, provide to such auditors (including external auditors and Enbridge's internal audit staff or agents) as Enbridge may designate in writing, supervised access to the data, records and supporting documentation maintained by the Consultant with respect to the Services solely for the purpose of: (i) performing audits and inspections to enable Enbridge to satisfy applicable regulatory requirements or certify compliance with applicable laws; and (ii) to confirm that the Services are being provided in accordance with the terms of this Agreement. Enbridge and its auditors shall use commercially reasonable efforts to conduct such audits in a manner that will result in a minimum of inconvenience and disruption to the Consultant's business operations. In the event that if any such audit reveals any: (a) errors or deficiencies in the completion of the Services or invoicing of the Services; or (b) overpayments to the Consultant by Enbridge, then the Consultant shall forthwith correct such errors or deficiencies, including if applicable refunding any overpayment to Enbridge. The Consultant shall retain all records for three (3) years from the date of expiration or earlier termination of this Agreement, or such longer period as Enbridge may require having regard to the nature of the Services. Enbridge and its auditors may not have access to information deemed proprietary, trade secret, and/or confidential by the Consultant.

25. **Enbridge Policies**

The Consultant acknowledges receipt of a copy of each of Enbridge Inc.'s Statement on Business Conduct for Enbridge Inc. and its Subsidiaries and Lifesaving Rules, each as amended from time to time (the "Policies"). The Consultant agrees to comply with the Policies in connection with its delivery of the Services described in this Agreement, and agrees that, if requested by Enbridge, it will ensure all personnel delivering the Services herein attend training on the Lifesaving Rules.

26. **ISNetworld Requirement**

If required by Enbridge, the Consultant shall subscribe with ISN Software Corporation as a registrant of ISNetworld ("ISN") or any successor service mandated by Enbridge from time to time, and maintain a performance grading within ISN that is acceptable to Enbridge (the "ISNetworld Requirement") and shall: (a) provide all records and information as required by ISN or Enbridge, including, but not limited to, training and qualification data of the Consultant personnel, including subcontractors and employees, relating to the Services; and (b) maintain compliance with the ISNetworld Requirement during the currency of this Agreement.

[remainder of page intentionally left blank]

27. **Counterparts and Execution**

This Agreement may be executed by the parties in separate counterparts, each of which when so executed and delivered will be deemed to be an original, and all such counterparts will together constitute one and the same instrument. Delivery of a signature by electronic transmission, including by email delivery of a "portable document format" ("pdf") document, shall create a valid and binding obligation. This Agreement may be executed using electronic signatures.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first written above.

CONCENTRIC ENERGY ADVISORS, INC.	**ENBRIDGE GAS INC.**
By: JMCoyne	By: Joel Denomy Joel Denomy (Jul 6, 2021 13:50 EDT)
Name: James M. Coyne	Name: Joel Denomy
Title: Senior Vice President	Title: Technical Manager Regulatory Applications
By:	By:
Name:	Name: * *
Title:	Title: *
(Please print name and title of Signing Officer)	

Witness: ______________________________

Name:

(Witness required if Contractor is a Sole Proprietor)

SCHEDULE A

TO THE CONSULTING AGREEMENT BETWEEN ENBRIDGE GAS INC. AND CONCENTRIC ENERGY ADVISORS, INC. Dated June 14, 2021

This Schedule is made under the above referenced consulting agreement (the "Agreement") between ENBRIDGE GAS INC. ("Enbridge") and CONCENTRIC ENERGY ADVISORS, INC. (the "Consultant").

1. **SCOPE OF SERVICES**

The Consultant will undertake the following Services:

Consultant will conduct an independent capital structure review to access the reasonableness of Enbridge's current capital structure.

As further defined in the attached letter detailing scope of work.

2. **DELIVERABLES**

The Consultant will provide the following deliverables:

• An assessment of Enbridge's business risk and financial risk compared to the last assessment that was reviewed by the OEB;
• An assessment of Enbridge's prospective business risk and financial risk;
• An examination of information on utility actual and approved capital structures;
• A comparison of other North America utility capital structures to Enbridge's current and proposed capital structure;
• Provision of a recommendation on the appropriate common equity level for Enbridge; and
• A written report detailing all of the above.

3. **TERM AND COMMENCEMENT AND COMPLETION DATES**

This Schedule shall be effective as of June 14, 2021 and expire December 31, 2023, or such other date as the parties may mutually agree in writing.

4. **KEY PERSONNEL**

The Consultant will provide the following personnel to deliver the services set out above under Scope of Services:

Jim Coyne, SVP
Robert C. Yardley, Jr., SVP
Dan Dane, SVP
Jacob Hurwitz, Project Manager

5. **FEES AND PAYMENT TERMS**

[redacted]

[redacted]

Expenses: N/A

The above fees and expenses cannot be exceeded without prior written approval from Enbridge.

Fees are payable by Enbridge within sixty (60) days of receipt from the Consultant of an appropriate invoice setting out in reasonable detail the nature of the services provided.

[Remainder of page intentionally left blank; signature page to follow]

Dated as of June 30, 2021.

CONCENTRIC ENERGY ADVISORS, INC.

By: ______________________
Name: James M. Coyne
Title: Senior Vice President

By: ______________________
Name:
Title:
(Please print name and title of Signing Officer)

Witness: ______________________
Name:

(Witness required if Contractor is a Sole Proprietor)

ENBRIDGE GAS INC.

By: Joel Denomy
Joel Denomy (Jul 6, 2021 13:50 EDT)
Name: Joel Denomy
Title: Technical Manager Regulatory Applications

By: ______________________
Name: * *
Title: *

ENBRIDGE

Joel Denomy
Technical Manager
Regulatory Applications

Tel: 416-495-5499
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

Via Email

May 28, 2021

James M. Coyne
Senior Vice President
Concentric Energy Advisors
jcoyne@ceadvisors.com

Dear Mr. Coyne,

Re: Capital Structure – Scope of Work

Enbridge Gas Inc. (Enbridge Gas) is a Canadian natural gas utility regulated by the Ontario Energy Board (OEB). Enbridge Gas provides safe, reliable and cost-effective natural gas distribution, transmission, storage and related services to approximately 3.8 million customers throughout the province of Ontario. Enbridge Gas also provides natural gas storage and transmission services to other utilities and customers located outside of Ontario. Enbridge Gas is North America's largest natural gas utility by volume, and third largest by customer count. Enbridge Gas was formed on January 1, 2019 with the amalgamation of Enbridge Gas Distribution and Union Gas.

Enbridge Gas is currently in the third year of a five-year deferred rebasing period following the aforementioned amalgamation. The deferred rebasing period term runs from 2019 to 2023. Rates during the deferred rebasing period are set using an incentive rate setting mechanism (IRM) whereby rates are adjusted annually using a price cap model.

Enbridge Gas is currently preparing to file a rebasing application (the 2024 rebasing application) with the OEB for rates commencing January 1, 2024. This application will include a cost of service (or rebasing) component in addition to a proposal for an IRM[1] to set rates through to 2028.

Enbridge Gas' rate base is financed by a combination of common equity and long-term and short-term debt, the ratios for which are approved by the OEB. The current OEB approved capital structure for Enbridge Gas is comprised of 36% common equity and 64% long-term and short-term debt.

The cost included in rates associated with these financing instruments is determined in different ways. An OEB approved formula is used to determine the return on equity (ROE) applied to common equity. The yield on long-term debt when issued plus the

[1] The OEB provides two options that a utility can propose as an IRM: a price cap model or a custom incentive regulation model.

forecast cost of any new issuances is used to determine the cost of long-term debt. The cost of short-term debt is determined by a forecast of the cost of short-term debt. As part of the 2024 rebasing application Enbridge Gas would like to investigate the suitability of its current capital structure, specifically if 36% common equity is appropriate. For this investigation it should be assumed that the OEB approved ROE formula will apply.

This investigation is intended to address three main concerns: 1) Enbridge Gas' capital structure relative to other regulated utilities, 2) Enbridge Gas' ability to finance capital expenditures in 2024 and during the IRM term; and 3) The appropriateness of Enbridge Gas' capital structure in terms of i) business risk relative to the last time capital structure was assessed and approved by the OEB and ii) prospective business risks.

To support Enbridge Gas' investigation and a possible request of the OEB to approve a different capital structure in the 2024 rebasing application, Concentric Energy Advisors (Concentric) has agreed to conduct an independent capital structure review to assess the reasonableness of Enbridge Gas' current capital structure.
Concentric's deliverables are as follows:

- An assessment of Enbridge Gas' business risk and financial risk compared to the last assessment that was reviewed by the OEB;
- An assessment of Enbridge Gas' prospective business risk and financial risk;
- An examination of information on utility actual and approved capital structures;
- A comparison of other North America utility capital structures to Enbridge Gas' current and proposed capital structure;
- Provision of a recommendation on the appropriate common equity level for Enbridge Gas; and
- A written report detailing all of the above

The written report detailing Concentric's findings and recommendations resulting from the independent assessment will be subject to a stakeholder engagement process and may be filed with the OEB as part of the 2024 rebasing application. It is likely that the OEB will hold an oral hearing for the 2024 rebasing application. Concentric may be required to participate in the stakeholder engagement process and the OEB proceeding process (including any and all processes set out by the OEB related to the 2024 rebasing application). In addition, Enbridge Gas may seek, from time to time, input from Concentric on other regulatory matters that are related to capital structure and cost of capital.

Concentric's participation in the stakeholder engagement and proceeding process may include but not be limited to:

- Presentation of the results of the independent assessment to stakeholders;
- Preparation of the written report which may be filed with the OEB;
- Responding to interrogatories and undertakings; and
- Appearing as a witness on behalf of Enbridge Gas in the 2024 rebasing application, as required

Concentric should recognize that during the course of performing the aforementioned activities for Enbridge Gas it could receive, deliver, prepare, review, analyze, reproduce, summarize or otherwise work with confidential and propriety information. Concentric agrees to treat all such information as confidential and privileged.

Enbridge Gas is requesting that Concentric provide a draft assessment report to Enbridge Gas by August 2021. Timing of a final report will be dependent on timing of the 2024 rebasing application filing.

In terms of remuneration for this work Enbridge Gas requests that Concentric provide a cost estimate based on the deliverables outlined above. It is expected that the cost estimate includes a fixed price for preparation of the report.

Any questions or correspondence regarding the scope of the independent investigation and/or the deliverables should be submitted to:

Joel Denomy,
Technical Manager, Regulatory Applications
500 Consumers Road
North York, Ontario, Canada
M2J 1P8
joel.denomy@enbridge.com

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/p. 2 and January 27 update

Question(s):

The forecast total revenue deficiency is now $294.1 million. Please provide one schedule setting out how the $294.1 million was calculated itemizing all of the impacts including depreciation, adjustments to the capital structure, the increasing cost of providing service to customers and the offsetting savings.

Response:

Please see Exhibit 6, Tab 1, Schedule 2, Attachment 1, page 1, updated March 8, 2023, for the split of $294.1 million of deficiency between delivery and gas supply.

For further details on drivers, please see the following:

- For delivery revenue deficiency of $270.9 million - Exhibit 6, Tab 1, Schedule 2, Attachment 2, page 2, updated March 8, 2023 and response at Exhibit I.6.1-SEC-206, and

- For gas supply deficiency of $23.2 million - Exhibit 6, Tab 1, Schedule 2, Attachment 3, Page 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2

Question(s):

On January 27, 2023 EGI filed an update to its evidence. Does EGI intend to file any more updates or additional evidence in support of its Application? If so, please indicate what that evidence will consist of and the expected timing.

Response:

As stated in its January 27, 2023 letter, concurrent with its interrogatory responses, Enbridge Gas is filing evidence corrections and updates for the impacted Exhibits.

With respect to additional evidence related to Phase 1 of the proceeding, Enbridge Gas notes the following:

- The Company received the OEB's Decision on the Rate Order for its multi-year DSM Plan[1] and is considering how to address the direction given by the OEB.
- In responding to Exhibit I.1.10-ED-66 Guidehouse discovered an error in its modeling for the P2NZ, which has potential impacts to its report. Once confirmed, Guidehouse will update the P2NZ Report.
- In responding to Exhibit I.4.5-STAFF-178 Concentric noted that at the time of its study it did not have certain historical data, which it has now received from Enbridge Gas. An amended depreciation study may be filed based upon the additional data.

[1] Decision and Order, EB-2021-0002, Enbridge Gas Inc. Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027), March 2, 2023, p. 5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/p. 4

Question(s):

Overall, Enbridge Gas is requesting a 4% increase in revenues in 2024. The rates would result in annual bill increases for 2024 of up to 3% for customers in the EGD rate zone, an increase of up to 8% for customers in the Union South rate zone and a decrease of 3-13% for customers in the Union North rate zone:

a) Please explain how EGI determined what would be acceptable rate levels for each of its rate zones;

b) Do these include impacts of deferral and variance account dispositions? If not, please provide these impacts;

c) Please indicate when the rate impacts were finalized by the Board of Directors;

d) Please explain the extent to which EGI presented annual bill impacts to its customers as part of its customer engagement;

e) Please explain if EGI, in its customer consultations, referred to increasing gas costs in order to give its customers s complete picture of the potential bill impacts that customers will face?

f) In calculating these bill impacts what has EGI assumed regarding gas costs?

g) Has EGI completed a forecast of bill impacts assuming continued increases in natural gas pricing? If not, why not? If so, please provide that analysis.

h) Has EGI prepared a five-year gas cost forecast? If not, why not?

Response:

a) The OEB required Enbridge Gas to file a proposal for rate harmonization with the current Application. In preparing the rate harmonization proposal and assessing alternatives, Enbridge Gas tried to balance rate impacts across all rate classes and performed a detailed and comprehensive review of bill impacts by customer. To assess whether the proposal to harmonize rates could be proposed for implementation, Enbridge Gas recognized the OEB policy requiring a rate mitigation measures when the effects of harmonization result in bill increases for any customer class that are material.[1]

   The OEB has a policy requiring the filing of a mitigation plan when the total bill impact is 10% or more for any customer class.[2] While the OEB notes that this policy is applicable to electricity distributors, the OEB expects all other utilities to propose mitigation plans, or explain why a plan is not required, when the proposal results in material impacts to customers.[3] The OEB most recently confirmed the applicability of the 10% bill impact threshold to Enbridge Gas's business in its decision on the Company's July 2022 QRAM which states:

   > The OEB uses a 10% total bill impact extensively for the electricity sector and considers that a reasonable target for the natural gas sector as well. This threshold is referenced in the OEB's Handbook for Utility Rate Applications applicable to all rate-regulated utilities.[4]

   Enbridge Gas calculated total bill impacts, including gas supply commodity charges, to evaluate the bill impacts for all rate classes against the 10% bill impact threshold referenced above. Details regarding the bill impact results and proposed rate mitigation plan is provided at Exhibit 8, Tab 2, Schedule 6.

b) The bill impacts listed at Exhibit 1, Tab 2, page 4 include the impact of deferral and variance account dispositions. The typical bill impacts for each rate class including and excluding rate riders is also provided at Exhibit 8, Tab 2, Schedule 6, Table 4.

c) Rate impacts were presented to the Enbridge's Board of Directors on October 25, 2022. Please see response at Exhibit I.1.2-CCC-1, Attachment 1.

d) Annual bill impacts, which were based on the draft plan, were shown within the Phase Three workbooks for general service and contract customers. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 247, 272, 330, 359, 432, and 448

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[1] Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p.36.
[2] Handbook for Utility Rate Applications, October 13, 2016, Appendix 3, p.v.
[3] Ibid.
[4] EB-2022-0150, Decision and Rate Order, June 16, 2022, p.3.

for annual forecasted bill impacts before and after choices in the workbook were made.

e) Enbridge Gas did not refer to a potential increase in gas commodity costs in its customer consultations. It did, however, refer to the increase in the Federal Carbon Charge.

f) The bill impacts in this Application have been prepared based on the forecast of gas costs provided at Exhibit 4, Tab 2, Schedule 1 and include the weighted average reference price based on the 12-month commodity price forecast approved in the April 1, 2022 QRAM. The reference price will be updated for the most recent OEB-approved QRAM as part of the draft rate order process, in accordance with the filing requirements[5].

g) Enbridge Gas has not prepared bill impacts assuming continued increases in natural gas pricing, as this is not part of the filing requirements[6]. The Application is for approval of rates for the sale, distribution, transmission, and storage of gas commencing January 1, 2024, not for commodity-related rate changes.

h) Enbridge Gas has prepared a four-year gas cost forecast for the years from 2023 to 2026 in alignment with the corporate long-range plan process as described at Exhibit 2, Tab 6, Schedule 1. The four-year gas cost forecast is based on the 12-month commodity price forecast approved in the April 1, 2022 QRAM.

[5] Filing Requirements For Natural Gas Rate Applications, February 16, 2017.
[6] Ibid.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/p. 4

Question(s):

Please provide a detailed breakdown of the $121.2 million in annual integration and productivity savings realised during the 2019-2023 rebasing term. Are these all OM&A savings or a combination of OM&A and Capital.

Response:

The $121.2 million in annual integration and productivity savings for the deferred rebasing term and for the 2024 Test Year is broken down in Table 2. All are O&M savings. For detail on the integration initiatives please see response at Exhibit I.1.9-CCC-25. For productivity definitions please see response at Exhibit I.1.9-SEC-90.

Table 1

			Savings in $millions					
Line No.	Savings	Type	2019	2020	2021	2022	2023	2024
			(a)	(b)	(c)	(d)	(e)	(f)
	Integration							
1		Alignment of Policies, Programs, Processes & Procedures	1.7	3.4	5.5	5.6	5.7	5.7
2		Cost Rationalization	2.6	4.2	4.9	4.9	4.9	4.9
3		Customer Care Integration	2.8	2.9	1.8	16.8	16.8	16.8
4		Integration & Execution of Operating Models		0.1	4.3	3.7	3.7	3.7
5		Organizational Restructuring (Labour)	25.1	41.8	54.8	54.8	54.9	54.9
	Productivity							
6		Alignment of Policies, Programs, Processes & Procedures	5.4	15.9	15.9	14.9	14.9	14.9
7		Embedded Productivity					13.9	18.1
8		Cost Rationalization	2.8	2.7	2.7	2.7	2.2	2.2
	Total		40.4	71.0	89.9	103.4	117.0	121.2

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/p. 15

Question(s):

The evidence states that the Energy Transition Plan has been informed by Enbridge Gas's understanding of current energy transition and climate policies, stakeholder input and a review of research and studies, both external and commissioned by the Company. Energy transition has been incorporated into Enbridge Gas's forecasting and planning processes by including energy transition assumptions in forecasting, in the efforts to include Integrated Resource Planning (IRP) in the AMP and by accounting for energy transition in the Company's finance and regulatory approaches and stakeholder engagement.

a) Please provide a list of all studies EGI has relied on in this context regarding energy transition;

b) Please explain in detail how energy transition has been specifically incorporated in EGI's forecasting for the rate plan term. What energy transition assumptions have been included in this forecasting?

c) How has energy transition been accounted for in the Company's finance and regulatory approaches?

Response:

a) The following studies helped inform Enbridge Gas's Energy Transition Plan:

   i. The Energy Transition Scenario Analysis Study, provided at Exhibit 1, Tab 10, Schedule 5, Attachment 1;

   ii. The Pathways to Net-Zero Emissions for Ontario Study, provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2; and

   iii. The Rebasing Scenario Report, provided at Exhibit 1, Tab 10, Schedule 6, Attachment 1.

b) Please see Exhibit 1, Tab 10, Schedule 4, pages 1 to 12.

c) Please see Exhibit 1, Tab 10, Schedule 4, pages 16 to 20.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/p. 16

Question(s):

The evidence states that energy transition planning is not only reflected in the Company's "safe bet" actions, but also in the way Enbridge Gas is forecasting growth, managing risk and allocating capital. Please explain specifically how energy transition planning is impacting the way in which EGI manages risk and allocates capital. How is this different from what EGI has done in the past?

Response:

Please see Exhibit 1, Tab 10, Schedule 4, pages 12 to 20 for a description of how Enbridge Gas is proposing to manage energy transition-related risk in the Company's capital planning and finance approaches, as compared to traditional approaches.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/p. 17

Question(s):

The Concentric study concluded that the combination of the lowest deemed equity ratio and the low authorized ROEs in recent years places Enbridge Gas at a competitive disadvantage in terms of attracting capital and compensating existing shareholders. Please provide evidence (other than the conclusions reached by Concentric) to support the claim that Enbridge Gas has experienced a competitive disadvantage in terms of attracting capital or will face a competitive disadvantage.

Response:

The OEB-approved debt to equity ratio impacts the financial metrics credit rating agencies use to assess Enbridge Gas's financial risk. The ability to maintain a strong, investment-grade credit rating is an important factor in Enbridge's ability to continue to secure debt funding at cost effective rates. As business risk increases, having the lowest deemed equity ratio amongst peers does not help maintain a strong, investment grade credit rating. Please see response at Exhibit I.5.3-VECC-58 parts c-d) for more information on rating agencies' views towards the energy transition and increased risks to utilities.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/S1/p. 21

Question(s):

The evidence states that EGI is expecting it will add 40,000 new customers in 2024, in line with growth in recent years. The long-range forecast that underpins EGI's customer connection forecast does reflect a gradual decline in the number of new customers that are connected over the AMP's 10-year planning period, as a wider variety of energy solutions become available:

a) Please provide a table setting out the total customer additions for each year 2013-2022 for the previous EGD and Union Gas Limited and the merged EGI;

b) Please provide the customer additions assumed for 2023;

c) Please provide the customer additions assumed for each year of the 10-year planning period.

Response:

a-b) Please see response at Exhibit I.3.2-LPMA-22, Attachment 1.

c) Please see response at Exhibit I.1.10-STAFF-31, Tables 16 and 17 for Customer Additions Forecast before and after energy transition assumptions, respectively.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/S1/p. 22

Question(s):

The evidence states that Enbridge Gas is also connecting communities that have not had access to natural gas in the past. Through phase 1 and phase 2 of the Natural Gas Expansion Program the Company has helped residents nine community expansion areas switch from higher emitting fuels to natural gas since 2019. An additional 22 community expansion projects are slated to start construction by the end of 2025:

a) Please provide a complete description of the Natural Gas Expansion Program.

b) Please indicate what phase 1 and phase 2 has consisted of.

c) Please list each of the nine communities and describe each project - providing the cost of the project, any surcharges paid by customers, the number of customers connected and expected to be connected. Also, please indicate whether grants were provided for each project and the level of the grant;

d) Please list each of the additional 22 communities and describe each project – providing the cost of the project, any surcharges paid by customers, and the number of customers expected to be connected. Also, please indicate whether grants are to be provided for each project and the level of each grant;

e) How are the grants from the Province treated from an accounting perspective?

f) What is the current status of the program? Does EGI expect additional communities will be connected beyond the 22 that are slated for construction by the end of 2025?

Response:

a) The Natural Gas Expansion Program (NGEP) was created under the Access to Natural Gas Act, 2018, to help expand access to natural gas to areas of Ontario that currently do not have access to the natural gas distribution system. This program encourages communities to partner with gas distributors on potential expansion projects that would not be built without additional financial support and submit information on these proposals to the OEB.

Phase one of the NGEP was announced in March 2019 with approximately $56 million allocated funding. Phase one of the program supported seven community expansion projects and two economic development projects.

In Phase two of the NGEP, the OEB accepted information submissions on potential projects from utilities for natural gas expansion projects.

The OEB compiled a report on all submissions they received for the ministry's review and released it to the public on December 10, 2020. In June 2021, the Ontario Government announced funding for 26 community expansions and two economic development projects under Phase Two of the NGEP.

b) For the full list of awarded projects under the NGEP phase one and phase two, please refer to the Ontario Regulation 24/19: Expansion of Natural Gas Distribution Systems consolidated from June 8, 2021, under the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B. Schedule 1 and Schedule 2[1].

c) The following consists of the four community expansion projects under NGEP phase one and the five community expansion projects under NGEP phase two, which are in execution.

Table 1

Project Name	Cost of the Project	Number of customers expected to connect
Scugog Island	$16,550,837	810
Chippewa of the Thames First Nation	$1,863,000	44
Saugeen First Nation	$3.314.000	89

[1] O. Reg. 24/19: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS (ontario.ca)

Project Name	Cost of the Project	Number of customers expected to connect
Northshore and Peninsula Rd	$10.095.000	134
Brunner	$ 1,293,836	44
Kenora District (Hwy 594)	$1,551,582	30
Stanley's Old Maple Lane Farm	$820,779	11
Burks Falls	$1,663,917	41
Haldimand Shores	$4,048,709	112

Please see response at Exhibit I.1.12-FRPO-21 for the other information requested.

The NGEP grant for the above nine community expansion projects were released by the IESO in full amount in accordance with the Ontario Regulation 24/19: Expansion of Natural Gas Distribution Systems consolidated from June 8, 2021 under the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B. Schedule 1 and Schedule 2[2].

d) The following consists of the 2 community expansion projects under NGEP phase one and the 20 community expansion projects under NGEP phase two that are in development. /u

Project Name	Cost of the Project	Number of customers expected to connect
Hiawatha First Nation	$5,286,857	213
Cornwall Island	$8,418,045	354
Bobcaygeon	$116,714,815	3,978

[2] O. Reg. 24/19: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS (ontario.ca)

Project Name	Cost of the Project	Number of customers expected to connect
Hidden Valley	$3,463,661	110
Mohawks of the Bay of Quinte	$10,715,495	179
Selwyn	$4,502,425	87
Neustadt	$7,769,155	219
Prince Edward County (Cherry Valley)	$7,883,379	152
Sandford	$6,631,637	140
Eganville	$36,757,345	674
East Gwillimbury (North and East)	$15,563,359	422
Boblo Island	$2,776,579	92
Merrickville-Wolford	$4,024,120	67
St Charles	$8,602,563	162
Glendale Subdivision	$3,753,588	77

Project Name	Cost of the Project	Number of customers expected to connect
Chute-a-Blondeau	$9,038,505	318
Tweed	$5,091,557	62
Lanark and Balderson	$19,199,846	334
Red Rock First Nation (Lake Helen Reserve)	$4,081,700	77
Caledon (Humber Station)	$7,010,026	100
Severn (Washago)	$28,859,544	723
Cedar Springs	$3,479,788	103

The above 22 projects are in the development stages, and no customers have been connected.

The NGEP grants for the above twenty-two community expansion projects will be awarded in accordance with the Ontario Regulation 24/19: Expansion of Natural Gas Distribution Systems consolidated from June 8, 2021, under the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B. Schedule 1 and Schedule 2[3].

e) Enbridge Gas recognizes the IESO grants as a Contribution In Aid to Construct (CIAC) and accounts for the grants as a reduction to Property Plant and Equipment (PPE). The CIAC is applied to each approved project based on the funding distribution in the quarterly NGEP reports.

[3] O. Reg. 24/19: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS (ontario.ca)

f) Enbridge Gas is currently underway, with nine community expansion projects being in execution and actively servicing customers. The remaining 22 communities are in the development phases and Enbridge Gas intends to file LTC applications for all the projects. Enbridge Gas are not aware of any additional community expansion projects beyond the current phase of the NGEP Program.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/S1/p. 22

Question(s):

Please provide a detailed comparison of the annual savings achieved during the 5-year rebasing period ($86 million) and the estimated first 5 years included in the 10-year submission in the MA[A]DS Application. Please also provide a detailed comparison of the integration costs.

Response:

The MAADs Application included ranges for integration capital costs and O&M savings over the requested 10-year term. The range of potential capital investment as filed was $50 - $250 million and the range of potential O&M savings was $350 - $750 million over the requested 10-year term. As noted in the filing, these ranges were estimates, and detailed planning would be undertaken once an OEB decision was rendered. It was also noted that the integration could not proceed as outlined with a term of 5 years.

After receiving the approval for a shortened 5-year deferred rebasing term, Enbridge Gas embarked on developing and executing integration plans and delivered $86 million in annual sustainable synergies, totaling $328 million over that period. This achievement exceeded the $81 million provided in the first five years noted in EB-2017-0306/EB-2017-0307 Exhibit C.BOMA.16 Attachment 1, page 10.

The comparison to the estimates as filed in the MAADs Application is as follows:

Table 1

Integration Costs/ Savings as Filed ($millions)

Item	Integration Savings Over 5 yr. Term 2019	2020	2021	2022	2023	Total	CapEx Investments Over 5 yr. Term 2019	2020	2021	2022	2023	Total
Customer Care		15	15	16	16	62		2	22	32	8	65
Distribution Work Management			11	11	11	33	7	21	21			50
Utility Shared Services		2	2	3	3	10	4	5	5			14
Storage & Transmission		1	3	3	3	10		8				8
Management		20	20	20	20	80						0
Other Functions									5	5	5	13
Additional Unidentified Efficiencies	3		12	17	28	60						
Total	3	38	63	70	81	255	11	36	53	37	13	150

Notes:

1) Filing contemplated a 10-year term; reference: EB-2017-0306/EB-2017-0307, Exhibit C.BOMA.16, page 10, truncated at 5 years

Table 2

Integration Costs/ Savings as Achieved ($millions)

Aligned to MAADS Categories	Integration Savings Over 5 yr. Term 2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	Total Over Term	CapEx Investments Over 5 yr. Term 2019 Actuals	2020 Actuals	2021 Actuals	2022 Estimate	2023 Bridge Year	Total CapEx Over Term
Customer Care	3	4	5	20	20	51	8	32	32			72
Distribution Work Management	1	3	10	9	9	32	18	10	19	26	14	86
Utility Shared Services	4	9	16	16	16	60			25	11	30	67
Storage & Transmission	2	5	6	6	6	24	4	7	8	5	0	24
Management	19	27	30	30	30	136						0
Other Functions	3	5	5	5	5	23		1	2			3
Total	32	52	71	86	86	328	29	50	87	42	44	252

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/S1/p. 23

Question(s):

Please provide a copy of the documents defining the Voluntary Workforce Options (VWO) program. Please indicate how many employees participated in the VWO program in each year and the overall cost of the program.

Response:

Please find a copy of the VWO Program documents in Attachment 1.

As provided at Exhibit 1, Tab 9, Schedule 1, paragraph 9, 244 full-time equivalent employees participated in the VWO Program in 2020 at Enbridge Gas. In addition, 83 full-time equivalent employees participated in the VWO Program in central functions for a total of 327 full-time equivalents. The severance cost related to the VWO Program was $77.7M for 2020.

Leaves of Absence Information Package - Canada

May 2020

Voluntary Workforce Options

ENBRIDGE®

Overview

- Participation in the VWO program is optional for eligible employees. Eligible employees can choose to apply for the program, if interested, or choose not to participate at all.
- The information in this document is intended to provide employees with a detailed overview of the Leaves of Absence options under the VWO program.
- Detailed FAQs can be found on Elink.
- Questions about the program should be directed to **a dedicated VWO team** in HR:
  - Call MyHR at 1-877-613-6247 or *6947 and press 5 to speak with a VWO Advisor directly
  - Send an email to VWOProgram@enbridge.com

Voluntary Workforce Options

Educational Leave of Absence - Canada

Voluntary Workforce Options Program

Educational Leave of Absence Details - Canada

Program Name	Leaves of Absence
Program Option	Educational Leave
Eligibility	• All non-union regular employees • Leader review and approval required
Parameters	• Opportunity to upgrade education or reskill while remaining employed; education must be relevant to Enbridge • Up to two years; minimum 6 months; leave must commence by January 2021 at the latest; duration of leave must be decided upfront • A two-year return service agreement covering the value of both the education reimbursement and base pay incentive is required • If there is no job to return to at the end of the leave, severance will be based on pre-leave status
Education Reimbursement	• Up to $20,000 tuition reimbursement (grossed up for taxes after maximum allowable reimbursement) • You must provide receipts for your education program costs and will be reimbursed up-front. You must also provide proof of successful completion; otherwise, the full tuition reimbursement amount you received will be payable to the Company.

Base Pay Incentive	• 20% of base pay in effect on May 31 (pre-reduction) while on leave; paid in lump sum payments as follows:
	    • 20% of base pay for period: 1st day of leave to December 31, 2020 paid on the first pay period after the start of the leave
	    • 20% of base pay for period of leave in 2021 paid on the second pay of January 2021
	    • 20% of base pay for period of leave in 2022 paid on the second pay of January 2022

Voluntary Workforce Options Program

Educational Leave of Absence Details - Canada

Program Name	Leaves of Absence
Program Option	Educational Leave
STIP	• You are eligible for a STIP award that will be pro-rated based on the time you were actively employed and working in your job during the calendar year
LTIP	• If you are eligible for LTIP, you will continue to be eligible for annual grants while on leave of absence. Awards will be prorated at the time of payout for active service during the applicable term.
Enbridge Employee Savings Plan	• Matched and non-matched contributions stop during unpaid leaves. Contributions can be restarted upon return to work.
Pension	• Pension accrual stops after 31 days of unpaid leave
Time off	• You will not accrue vacation after the first 31 days of the leave. • If you have unused, accrued vacation it should be used prior to the start of your leave.
Benefits	• Benefits are employer-paid for up to 2 years • All benefits (Life, AD&D, LTD, Critical Illness, EHC, Dental, HSA) cease on the date the employee starts to work in another job more than 20 hours per week.

Voluntary Workforce Options Program

Educational Leave of Absence Details - Canada

Program Name	Leaves of Absence
Program Option	Educational Leave
Extended Health Care and Dental	• These benefits continue
EFAP	
Emergency Medical and Travel Assistance (Out-of-Country Coverage)	
Health Spending Account (HSA)	• You can continue to use your remaining 2020 HSA balance for the remainder of 2020. The Company will cover the cost of your contributions from the time your Leave starts to the end of the year. • You are not eligible to make an HSA election for 2021 unless and until you return to active service in 2021. • If your leave starts in January, 2021 (the latest you can start your leave), you will not be eligible to make an HSA election for the 2021 calendar year during the annual re-enrolment period in November, 2020.
Short Term Disability (STD)	• If you become disabled during the unpaid leave, the 26-week STD benefit period commences on your date of disability. If you are approved for STD, and you are scheduled to return to work before the end of the benefit period, STD benefits will start on your scheduled return date. Example: if you are scheduled to return to work 10 weeks after your date of disability, you may receive STD benefits for up to 16 weeks.
Long Term Disability (LTD)	• Benefit continues. If you become disabled during the unpaid leave, the qualifying period for LTD benefits commences on your date of disability. If you are approved for LTD claim, benefit payments start on the later of: a) the date you satisfy the elimination period; or b) the date you were scheduled to return to work.

Voluntary Workforce Options Program

Educational Leave of Absence Details - Canada

Program Name	Leaves of Absence
Program Option	Educational Leave
Critical Illness Insurance (Employee & Spouse) Life Insurance (Essential Employee, Optional Employee and Spouse) Optional Accidental Death & Dismemberment Insurance (Employee and Dependent(s))	• These benefits continue. You will not be required to pay for missed contributions upon your return to work. • These benefits continue and Enbridge pays for these benefits while you are on an approved leave.
Business Travel Accident Insurance	• Coverage for Business Travel Accident **ceases** while on leave
Wellness Program	• This program is not available while on leave. You should load all Wellness and Stellar dollars onto your Stellar card prior to leave.
Higher Education Awards Program	• All approved awards will be paid. Employees are eligible to participate in the program while on leave.

Personal Leave of Absence - Canada

Voluntary Workforce Options Program

Personal Leave of Absence Details - Canada

Program Name	Leaves of Absence
Program Option	Personal Leave
Eligibility	• All non-union regular employees • Leader review and approval required
Parameters	• Opportunity for employees to pursue personal interests while remaining employed • Up to two years; minimum 6 months; leave should commence by June 28; exceptions require EVP and CHRO approval • Duration of leave must be decided upfront • If there is no job to return to at the end of the leave, severance will be based on pre-leave status

Base pay Incentive	• 10% base pay in effect on May 31 (pre-reduction) while on leave; paid in lump sum payments as follows:
	  • 10% of base pay for period: 1st day of leave to December 31, 2020 paid on the first pay period after the start of the leave
	  • 10% of base pay for period of leave in 2021 paid on the second pay of January 2021
	  • 10% of base pay for period of leave in 2022 paid on the second pay of January 2022

STIP	• You are eligible for a STIP award that will be pro-rated based on the time you were actively employed and working in your job during the calendar year
LTIP	• If you are eligible for LTIP, you will continue to be eligible for annual grants while on leave of absence. Awards will be prorated at the time of payout for active service during the applicable term.
Enbridge Employee Savings Plan	• Matched and non-matched contributions stop during unpaid leaves. Contributions can be restarted upon return to work
Pension	• Pension accrual stops after 31 days of unpaid leave

Voluntary Workforce Options Program

Personal Leave of Absence Details - Canada

Program Name	Leaves of Absence
Program Option	Personal Leave
Time off	• You will not accrue vacation after the first 31 days of the leave. • If you have unused, accrued vacation it should be used prior to the start of your leave.
Benefits	• All benefits (Life, AD&D, LTD, Critical Illness, EHC, Dental, HSA) cease on the date the employee starts to work in another job more than 20 hours per week.
Extended Health Care and Dental	• These benefits continue
EFAP	
Emergency Medical and Travel Assistance (Out-of-Country Coverage)	
Health Spending Account (HSA)	• You can continue to use your remaining 2020 HSA balance for the remainder of 2020. The Company will cover the cost of your contributions from the time your Leave starts to the end of the year. • You are not eligible to make an HSA election for 2021 unless and until you return to active service in 2021. • If your leave starts in January, 2021 (the latest you can start your leave), you will not be eligible to make an HSA election for the 2021 calendar year during the annual re-enrolment period in November, 2020.
Short Term Disability (STD)	• If you become disabled during the unpaid leave, the 26-week STD benefit period commences on your date of disability. If you are approved for STD, and you are scheduled to return to work before the end of the benefit period, STD benefits will start on your scheduled return date. Example: if you are scheduled to return to work 10 weeks after your date of disability, you may receive STD benefits for up to 16 weeks.

Voluntary Workforce Options Program

Personal Leave of Absence Details - Canada

Program Name	Leaves of Absence
Program Option	Personal Leave
Long Term Disability (LTD)	• Benefit continues. If you become disabled during the unpaid leave, the qualifying period for LTD benefits commences on your date of disability. If you are approved for LTD claim, benefit payments start on the later of: a) the date you satisfy the elimination period; or b) the date you were scheduled to return to work.
Critical Illness Insurance (Employee & Spouse)	• These benefits continues. You will not be required to pay for missed contributions upon your return to work.
Life Insurance (Essential Employee, Optional Employee and Spouse)	
Optional Accidental Death & Dismemberment Insurance (Employee and Dependent(s))	
Business Travel Accident Insurance	• Coverage for Business Travel Accident ceases while on leave
Wellness Program	• This program is not available while on leave. You should load all Wellness and Stellar dollars onto your Stellar card prior to leave.
Higher Education Awards Program	• All approved awards will be paid. Employees are eligible to participate in the program while on leave.

Reduced Work Hours Information Package - Canada

May 2020

Voluntary Workforce Options

ENBRIDGE®

Overview

- Participation in the VWO program is optional for eligible employees. Eligible employees can choose to apply for the program, if interested, or choose not to participate at all.
- The information in this document is intended to provide employees with a detailed overview of the Reduced Work Hours options under the VWO program.
- Detailed FAQs can be found on Elink.
- Questions about the program should be directed to **a dedicated VWO team** in HR:
  - Call MyHR at 1-877-613-6247 or *6947 and press 5 to speak with a VWO Advisor directly
  - Send an email to VWOProgram@enbridge.com

Voluntary Workforce Options

Part-time Option - Canada

ENBRIDGE

Voluntary Workforce Options Program

Part-time Details - Canada

Program Name	**Reduced Work Hours**
Program Option	**Part-time**
Eligibility	• All non-union regular employees • Leader review and approval required
Parameters	• Opportunity for employees to work reduced hours and balance other interests • A part-time employee either works fewer hours per day, or fewer days per week on an ongoing basis. Hours per week options: 16, 20, 24, 28, 30 & 32 • Must transition to part-time by mid-July • The duration is indefinite as long as business need is met

Base pay	• Base pay is pro-rated based on percentage time worked relative to a regular full-time position
	  • Where the reduction to the percentage time worked is 20% or greater, your new pay rate is calculated using your base pay in effect on May 31 (i.e. pre-reduction)
	  • Where the reductions to percentage time worked is less than 20%, your new pay rate is calculated using your base pay in effect on June 1 (i.e. including reduction)

STIP	• STIP is pro-rated based on % time worked and your new pro-rated base pay
LTIP	• If you are eligible for LTIP – normal rules apply; no impact on outstanding grants, future grants pro-rated based on new pro-rated base pay

Voluntary Workforce Options Program

Part-time Details - Canada

Program Name	Reduced Work Hours
Program Option	Part-time
Enbridge Employee Savings Plan	• Matched and non-matched savings contributions continue. Contributions can be changed at any time.
Pension	• Participants in Defined Contribution plan: you receive employer contributions based on pro-rated base pay. • Participants in Defined Benefit plan: you continue to participate and earn Credited Service pro-rated in accordance with the percentage of a regular full-time position and the plan will continue to recognize your full time equivalent base pay.
Time off	• Your vacation accrual will be prorated to your new work schedule effective the date of your schedule change. The time you accrued prior to the change in schedule does not change.
Extended Health Care and Dental Coverage	• You are eligible for benefits if your work schedule is 16 hours per week or 40% time worked and above • Your flex credit calculation will change according to your new base pay. If your new schedule is less than 24 hours per week, your single/couple/family flex credits will be reduced. • You can request to change benefit elections when switching from full-time to part-time
Health Spending Account (HSA)	• Benefit continues and contribution continues unchanged. You will have an opportunity to change your contribution at next open enrollment.
Short Term Disability (STD)	• No change in eligibility but any disability benefits received will be based on your new pro-rated base pay
Long Term Disability (LTD)	• No change in eligibility but coverage is based on your new pro-rated base pay

Voluntary Workforce Options Program

Part-time Details - Canada

ENBRIDGE

Program Name	Reduced Work Hours
Program Option	Part-time
Critical Illness Insurance (Employee & Spouse)	• This benefit continues if elected
Life Insurance (Essential Employee, Optional Employee and Spouse)	• Your life insurance coverage (essential and optional) will be based on your new pro-rated base pay. No change to your dependent life insurance.
Optional Accidental Death & Dismemberment Insurance (Employee and Dependent(s))	• Your employee optional AD&D coverage will be based on your new pro-rated base pay. No change to your dependent optional AD&D.
Business Travel Accident Insurance	• No change to eligibility but coverage is based on your new pro-rated base pay
EFAP	• These benefits continue
Emergency Medical and Travel Assistance (Out-of-Country Coverage)	
Wellness Program	
Higher Education Awards Program	

Job Share Option - Canada

Voluntary Workforce Options Program

Job Share Details - Canada

ENBRIDGE

Program Name	Reduced Work Hours
Program Option	Job Share
Eligibility	• All non-union regular employees • Leader review and approval required
Parameters	• Opportunity for employees to work reduced hours and balance other interests • Two part-time (.5 FTE/20 hours) employees with similar skills and experience are eligible to share one full-time position (1 FTE) • Participants must identify their job share partner; job share partner can be from a different department • Must transition to job share by mid-July (exceptions require EVP and CHRO approval) • The duration is indefinite as long as business need is met

Base pay	• Base pay is pro-rated based on percentage time worked relative to a regular full-time position
	  • Where the reduction to the percentage time worked is 20% or greater, your new pay rate is calculated using your base pay in effect on May 31 (i.e. pre-reduction)
	  • Where the reductions to percentage time worked is less than 20%, your new pay rate is calculated using your base pay in effect on June 1 (i.e. including reduction)

STIP	• STIP is pro-rated based on % time worked and your new pro-rated base pay
LTIP	• If you are eligible for LTIP – normal rules apply; no impact on outstanding grants, future grants pro-rated based on new pro-rated base pay

Voluntary Workforce Options Program

Job Share Details - Canada

ENBRIDGE

Program Name	Reduced Work Hours
Program Option	Part-time
Enbridge Employee Savings Plan	• Matched and non-matched savings contributions continue. Contributions can be changed at any time.
Pension	• Participants in Defined Contribution plan: you receive employer contributions based on pro-rated base pay. • Participants in Defined Benefit plan: you continue to participate and earn Credited Service pro-rated in accordance with the percentage of a regular full-time position and the plan will continue to recognize your full time equivalent base pay.
Time off	• Your vacation accrual will be prorated to your new work schedule effective the date of your schedule change. The time you accrued prior to the change in schedule does not change.
Extended Health Care and Dental Coverage	• You are eligible for benefits if your work schedule is 16 hours per week or 40% time worked and above • Your flex credit calculation will change according to your new base pay. If your new schedule is less than 24 hours per week, your single/couple/family flex credits will be reduced. • You can request to change benefit elections when switching from full-time to part-time
Health Spending Account (HSA)	• Benefit continues and contribution continues unchanged. You will have an opportunity to change your contribution at next open enrollment.
Short Term Disability (STD)	• No change in eligibility but any disability benefits received will be based on your new pro-rated base pay
Long Term Disability (LTD)	• No change in eligibility but coverage is based on your new pro-rated base pay

Voluntary Workforce Options Program

Job Share Details - Canada

Program Name	Reduced Work Hours
Program Option	Part-time
Critical Illness Insurance (Employee & Spouse)	• This benefit continues if elected
Life Insurance (Essential Employee, Optional Employee and Spouse)	• Your life insurance coverage (essential and optional) will be based on your new pro-rated base pay. No change to your dependent life insurance.
Optional Accidental Death & Dismemberment Insurance (Employee and Dependent(s))	• Your employee optional AD&D coverage will be based on your new pro-rated base pay. No change to your dependent optional AD&D.
Business Travel Accident Insurance	• No change to eligibility but coverage is based on your new pro-rated base pay
EFAP	• These benefits continue
Emergency Medical and Travel Assistance (Out-of-Country Coverage)	
Wellness Program	
Higher Education Awards Program	

Voluntary Program Information Package - Canada

May 2020

Non-Union Employees

Voluntary Workforce Options

ENBRIDGE®

Overview

- Participation in the VWO program is optional for eligible employees. Eligible employees can choose to apply for the program, if interested, or choose not to participate at all.
- The information in this document is intended to provide employees with a detailed overview of the Voluntary Program options under the VWO program.
- Participation caps have been set to mitigate risk to the business. Selected applicants will be determined based on a "lottery" if over subscribed.
- The application process is confidential; leaders will only be informed of approved applicants.
- Detailed FAQs can be found on ELink.
- Questions about the program should be directed to **a dedicated VWO team** in HR:
  - Call MyHR at 1-877-613-6247 or *6947 and press 5 to speak with a VWO Advisor directly
  - Send an email to VWOProgram@enbridge.com

Voluntary
Workforce Options

Voluntary Retirement - Canada

Voluntary Workforce Options Program

Voluntary Retirement Details - Canada

Program Name	Voluntary Program
Program Option	Voluntary Retirement
Eligibility	• Age 53 or older with 5 years service as of June 30, 2020
Parameters	• Severance is more generous than standard severance program, on average • Simple formula based on years of service x 5.2 weeks per year (notice period) • Minimum of 16 weeks, maximum of 104 weeks • Preferred transition date is June 26. Transitions beyond July 10 require EVP and CHRO approval
Severance	• Severance is calculated based on salary in effect on May 7 and years of service as of June 30 • Includes value of base pay, STIP (for active 2020 service and notice period, at target), Pension and Benefits during notice period • Severance is taxable and payable in lump sum amounts in 2020 and/or 2021 based on your election • Bridge to Retirement is available if within 2 years of age 55 OR age 55+ and within 2 years of reaching 30 years of service • Outplacement support available
STIP	• Pro-rated STIP for 2020 and the notice period is included in the severance payment, at target
LTIP	• Enhanced LTI treatment vs. standard treatment for an involuntary termination without cause • For details, please review the LTIP FAQ on ELink

Voluntary Workforce Options Program

Voluntary Retirement Details - Canada

ENBRIDGE

Program Name	Voluntary Program
Program Option	Voluntary Retirement
Savings Plan	• Savings Plan participation ends on your termination date • Contact Manulife to understand your savings plan options if you leave Enbridge
Pension	• Visit Financial Planning on ELink to access financial planning tools and resources • The Employee Pension Booklets describe your pension options if you leave Enbridge
Time off	• Unused accrued vacation will be paid out at final pay
Retiree Benefits	• You will transition to Retiree Benefits. Contact the VWO Team to confirm which retiree benefits plan you are eligible for.
Extended Health Care, Dental & Health Spending Account (HSA)	• Your active employee coverage ceases on your final pay date. You have 90 calendar days from that date to submit claims. You can also apply and pay for individual medical and dental insurance coverage under the “My Health Choice” program without proof of medical evidence provided you apply within 60 days of your benefit termination. Call Sun Life at (877) 893-9893.
EFAP	• This benefit continues for 90 days following your termination date

Voluntary Workforce Options Program

Voluntary Retirement Details - Canada

Program Name	Voluntary Program
Program Option	Voluntary Retirement
Short Term Disability (STD)	• Your coverage ends on your termination date
Long Term Disability (LTD)	
Critical Illness Insurance (Employee & Spouse)	• Your coverage ends on your termination date • If you are bridged to retirement, coverage for these benefits ends at the end of your bridging period • You have 31 calendar days from that date to convert your coverage to an individual policy without submission of medical evidence. Please contact MyHR at (877) 613-6247 if you are approved for Voluntary Retirement and wish to apply for conversion.
Life Insurance (Essential Employee, Optional Employee and Spouse)	
Optional Accidental Death & Dismemberment Insurance (Employee and Dependent(s)	• Your coverage ends on your termination date. You have 31 calendar days from that date to convert your coverage to an individual policy. To convert your policy, please contact AIG at (800) 387-4481. • If you are bridged to retirement, active employee coverage ends at the end of your bridging period
Emergency Medical and Travel Assistance	• Active Emergency Medical and Travel Assistance coverage ends on your final pay date • If you are bridged to retirement, active employee coverage ends at the end of your bridging period • You have 90 calendar days from that date to submit claims
Business Travel Accident Insurance	• Coverage ends on your termination date, as you will no longer be travelling on Company business

Voluntary Departure - Canada

Voluntary Workforce Options Program

Voluntary Departure Details - Canada

ENBRIDGE

Program Name	Voluntary Program
Program Option	Voluntary Departure
Eligibility	• Below Age 53 with at least 2 years of service OR Age 53 or older, with 2 – 5 years of service as of June 30, 2020
Parameters	• Severance is more generous than standard severance program, on average • Simple formula based on years of service x 4.8 weeks per year (notice period) • Minimum of 16 weeks, maximum of 104 weeks • Preferred transition date is June 26. Transitions beyond July 10 require EVP and CHRO approval
Severance	• Severance is calculated based on salary in effect on May 7 and years of service as of June 30 • Includes value of base pay, STIP (for active 2020 service and notice period, at target), Pension and Benefits during notice period • Severance is taxable and payable in lump sum amounts in 2020 and/or 2021 based on your election • Outplacement support available
STIP	• Pro-rated STIP for 2020 and the notice period is included in the severance payment, at target
LTIP	• Enhanced LTI treatment vs. standard treatment for an involuntary termination without cause • For details, please review the LTIP FAQ on ELink

Voluntary Workforce Options Program

Voluntary Departure Details - Canada

ENBRIDGE

Program Name	**Voluntary Program**
Program Option	**Voluntary Departure**
Savings Plan	• Savings Plan participation ends on your termination date. • Contact Manulife to understand your savings plan options if you leave Enbridge
Pension	• Visit Financial Planning on ELink to access financial planning tools and resources. • The Employee Pension Booklets describe your pension options if you leave Enbridge.
Time off	• Unused accrued vacation will be paid out at final pay
Extended Health Care and Dental	• Your coverage ceases on your final pay date. You have 90 calendar days from that date to submit claims. You can also apply and pay for individual medical and dental insurance coverage under the “My Health Choice” program without proof of medical evidence provided you apply within 60 days of your benefit termination. Call Sun Life at (877) 893-9893.
Health Spending Account (HSA)	• Your credits and coverage cease on your final pay date. You will have 60 calendar days following this date to submit claims.
EFAP	• This benefit continues for 90 days following your termination date.

Voluntary Workforce Options Program

Voluntary Departure Details - Canada

ENBRIDGE

Program Name	Voluntary Program
Program Option	Voluntary Departure
Short Term Disability (STD)	• Your coverage ends on your termination date
Long Term Disability (LTD)	
Critical Illness Insurance (Employee & Spouse)	• Your coverage ends on your termination date. You have 31 calendar days from that date to convert your coverage to an individual policy without submission of medical evidence. Please contact MyHR at (877) 613-6247 if you are approved for Voluntary Departure and wish to apply for conversion.
Life Insurance (Essential Employee, Optional Employee and Spouse)	
Optional Accidental Death & Dismemberment Insurance (Employee and Dependent(s)	• Your coverage ends on your termination date. You have 31 calendar days from that date to convert your coverage to an individual policy. To convert your policy, please contact AIG at (800) 387-4481.
Emergency Medical and Travel Assistance	• Active Emergency Medical and Travel Assistance coverage ends on your final pay date • You have 90 calendar days from your termination date to submit claims.
Business Travel Accident Insurance	• Coverage ends on your termination date, as you will no longer be travelling on Company business.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/S1/p. 23

Question(s):

EGI has consolidated its Customer Information System aligning billing process and migrating 1.6 million Union Gas customers to the one system. Please set out the overall cost of the CIS migration and provide year by year expenditures. When were those cost added to rate base?

Response:

Please see Table 1 for a summary of costs for the Customer Information System and SAP Hana Upgrade Project. The project went into service in July 2021, however only the residual net book value as of December 31, 2023 is being requested for approval as part of rate base in 2024. Please see Exhibit 1, Tab 9, Schedule 1 pages 20-25 for a summary of Enridge Gas's proposed treatment of integration capital projects.

Table 1

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	Total
		(a)	(b)	(c)	(d)
1	Customer Information System	5.0	29.2	28.8	63.0

Notes:

(1) Overheads included for all years

ENBRIDGE GAS INC.

Answer to Interrogatory from Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/S1/p. 24

Question(s):

EGI undertook a multi- year, phased project to bring the asset and work management system onto a common platform, creating a common system and processes for planning work, and harmonized policies, processes and procedures for distribution maintenance operations. Please set out the overall cost of this project and provide year by year expenditures. When were those costs added to rate base?

Response:

Please see Table 1 for a summary of costs. The Asset and Work Management System (AWS) Project is comprised of 3 phases: Phase 1 went into service in July 2021, Phase 2 in July of 2022 and Phase 3 is expected in 2023. However, only the residual net book value as of December 31, 2023 is being requested for approval as part of rate base in 2024. Please see Exhibit 1, Tab 9, Schedule 1 pages 20-25 and Exhibit 1, Tab 9, Schedule 1, Attachment 1 for a summary of Enbridge Gas's proposed treatment of integration capital projects.

Table 1

Line No.	Particulars ($ millions)	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	Total
		(a)	(b)	(c)	(d)	(e)
1	AWS	9.6	13.2	14.8	10.5	48.1

Notes:

(1) Overhead included for all years

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/S1/p. 28

Question(s):

What has been the annual impact of compliance with Bill 93 – Getting Ontario Connected Act on OM&A costs? What is the expected impact for 2023 and 2024?

Response:

Please see response at Exhibit I.4.4-STAFF-122.

ENBRIDGE GAS INC.

Answer to Interrogatory from Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/S1/p. 28

Question(s):

2024 OM&A will be further impacted by the inclusion of costs previously recovered separately through deferral accounts. Please identify all of these costs and the impact on 2024 OM&A costs.

Response:

Please see Table 1.

Table 1
Impact on 2024 OM&A of Cost Previously Recovered Separately Through Deferral Accounts

Line No	Item	Particulars ($ millions)
		(a)
1	IRP Operating Costs Deferral Account (IRPOCDA) (1)	1.8
2	GHG Emissions Administration Deferral Account (GHGEADA) (2)	1.4
3	OEB cost assessment Variance Account (OEBCAVA)	3.6
4	Accounting policy change Deferral Account (APCDA)	(17.7)
5	Total	(10.9)

Notes:
(1) Exhibit I.9.1-LPMA-47 part p).
(2) Exhibit I.9.1-LPMA-47 part h).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T2/S1/p. 30

Question(s):

The evidence states, “While Enbridge Gas has been collecting amounts for future abandonment within the net salvage component of depreciation rates for some time, the Company has concluded establishing a segregated fund is not in the best interests of customers at this time, as it would unnecessarily increase rates.” Please provide all analysis and studies produced to support this position.

Response:

Please see response at Exhibit I.4.5-SEC-193.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T3/S1/Attachment 1

Question(s):

Please describe the nature of the business activities undertaken by Enbridge Sustainable Energy Solutions Inc. When was this entity created? Please describe any interactions between this entity and EGI. Please explain how the activities undertaken by this entity relate to EGI's Demand Side Management programs.

Response:

Enbridge Sustainable Energy Solutions Inc. (ESESI) was incorporated in June of 2022. This entity was created as a holding company for non-regulated investments and has no direct interaction with Enbridge Gas. ESESI currently holds Enbridge's investment in Oakville Enterprises Corporation. ESESI does not undertake any activities related to Enbridge Gas's Demand Side Management programs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 1, Tab 2, Schedule 1, p. 3 of 34.

Question(s):

At page 3, EGI stated that "a distinct majority of customers who were engaged during the planning process supported Enbridge Gas's 2024 to 2028 business plan objectives, including those that would introduce higher costs." However, in a number of places within Innovative's reports, it's indicated that price/the cost of EGI's service was an important outcome to participants. For instance, at page 6 of 550 in Innovative's customer engagement report, Innovative noted that "lower rates was the most common comment among those that had a suggestion", and "providing affordable pricing" topped the ranked list of outcomes.

a) Please describe how EGI understands customer needs and preferences in the context of these results. For instance, does EGI understand customers to support business plan objectives that introduce higher costs despite their stated preference for lower rates, or only those specific investments proposed through the engagement, with other investments being less important than keeping rates low. Please explain fully.

b) Please provide EGI's position on how the proposed application responds to customer's indication that 'price' was the highest priority area where EGI has "room for improvement" (see page 8 of 550 of Innovative's customer engagement report)

Response:

a) The customer engagement process gauged customer needs and preferences in several ways: allowing customers to bring forward outcomes of importance for Enbridge Gas to consider (Phase One), rating outcomes individually (Phase Two), ranking outcomes relative to each other (Phase Two), and identifying support for specific investment options with concrete trade-offs between outcomes/priorities provided (Phase Three). Exhibit 1, Tab 6, Schedule 1, page 17, summarizes the rating and ranking exercises produced different lists of "top" outcomes, with reliability, safety, providing affordable pricing, and minimizing impacts on the environment at the top of these lists. Enbridge Gas understands these results to mean customers highly value several general outcomes. Enbridge Gas also understands that when it comes to specific investment decisions, there are trade-offs between these outcomes. Phase Three explored this, with customers being shown specific outcome trade-offs, including estimated bill impacts wherever possible, for specific investment choices. The Phase Three results – that reflect customer choices when presented with specific trade-offs and other contextual information – are the most relevant results for assessing customer preferences for the specific investments tested. In the case of investment decisions not tested through the customer engagement process, not being included does not mean these investments are less important than keeping rates low. Reasons for not including investments in the customer engagement process vary. Please see Exhibit 1, Tab 6, Schedule 1, page 12 for an overview of these reasons.

b) In Phase One, pricing was identified as both an area with room for improvement and something Enbridge Gas was doing well, Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 8. Phase One was exploratory in nature, with general results used to guide Enbridge Gas business planners before specific investment choices were developed.

c) As described in part a), providing affordable pricing was identified as an important outcome in Phase Two. The Application responds to this in several ways, including by passing $86 million in annual integration savings on to customers beginning in 2024. As seen in Phase Three results, customers are willing to accept rate increases to support specific investments and at least two thirds of customers (general service and contract) supported the draft rate increase included in the workbook as a result of the draft plan. Generally, customers also chose to spend more now to improve Enbridge Gas assets rather than delay, as reflected in the decision-making framework for the Asset Management Plan provided at Exhibit 2, Tab 6, Schedule 2, page 26.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

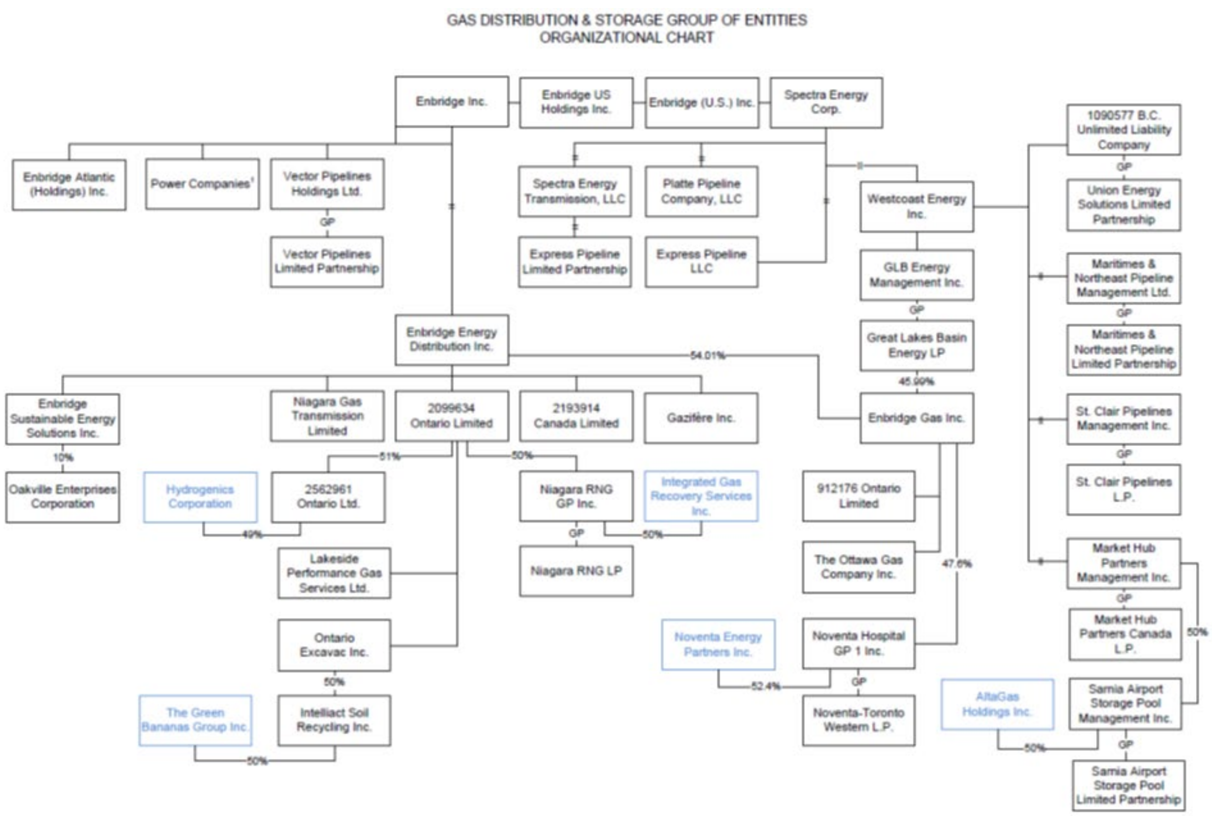
Interrogatory

Reference:

Exhibit 1, Tab 3, Schedule 1, Attachment 1, Page 1

Preamble:

The following org chart is found at the above reference



Question(s):

a) Please indicate how much profit Enbridge has earned from its regulated gas business in the past 5 years and how much it forecasts earning each year 2024 to 2028.

b) Please indicate how much profit Enbridge's parent and sister companies have earned from with respect to the gas pipelines that feed into Ontario. This is meant in part to explore the incentive facing the Enbridge families of companies to maintain gas volumes flowing into Ontario, and whether that may impact the relief sought by Enbridge

Response:

a) Regulated profit is defined by Enbridge Gas as net income applicable to common equity, which equals utility income less long and short term and preferred debt costs less income taxes. The regulated profit of Enbridge Gas in the past 5 years, for the years 2017 to 2021 is provided in Table 1 :

Table 1

Year/Utility	Reference	Net Income Applicable to Common Equity[1] ($ millions)
2017 – EGD	EB-2018-0131 - Ex B, Tab 1, Sch 2, line 37	239.0
2017 – Union	EB-2018-0105 - Ex A, Tab 2, App B, Sch 1, line 26	180.4
2018 – EGD	EB-2019-0105 - Ex B, Tab 2, App A, Sch 1, line 37	259.7
2018 – Union	EB-2019-0105 - Ex C, Tab 2, App B, Sch 1, line 26	208.8
2019	EB-2020-0134 - Ex B, Tab 1, Sch 1, line 20	495.5
2020	EB-2021-0149 - Ex B, Tab 1, Sch 1, line 20	425.6
2021	EB-2022-0110 - Ex B, Tab 1, Sch 1, line 20	469.5

Enbridge Gas forecasts regulated profit for 2022 through 2024 as provided in Table 2:

Table 2

Year/Utility	Reference	Net Income Applicable to Common Equity ($ millions)
2022	Exhibit 5, Tab 2, Schedule 1, Attachment 4, Pg 2[2]	490.8
2023	Exhibit 5, Tab 2, Schedule 1, Attachment 5, Pg 2[3]	496.5
2024	Exhibit 5, Tab 2, Schedule 1, Attachment 6, Pg 2[4]	535.8

[1] 2017 & 2018 EGD amounts are shown on a normalized basis and pre-earnings sharing.
[2] 2022 Net income applicable to common equity = forecast achieved earnings on common equity (9.028%) multiplied by common equity ($5,436.5M)
[3] 2023 Net income applicable to common equity = forecast achieved earnings on common equity (8.818%) multiplied by common equity ($5,630.4M)
[4] 2024 Net income applicable to common equity = allowed earnings on common equity (8.660%) multiplied by common equity ($6,186.8M)

As Enbridge Gas is setting cost of service rates for 2024 based on 2024 forecast information, Enbridge Gas declines to provide the requested forecast information beyond 2024. Any forecast of post-2024 profits will depend on the determinations in this proceeding.

b) The profits of Enbridge Gas's affiliates are not relevant to the approvals sought as part of the 2024 Rebasing Application. Further, Enbridge Gas's affiliates are not regulated by the OEB. Accordingly, Enbridge Gas declines to provide the requested information.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 2, Schedule 1, pg. 11

Preamble:

We would like to understand the rigour of EGI's customer engagement program.

Question(s):

Please provide the number of apartment owners that participate in each of the three distinct forms of engagement.

Response:

Enbridge Gas cannot confirm if specific respondents that completed the customer engagement were apartment owners or other representatives. To the best of its knowledge, at a minimum, 2 customers classified as "Apartment" were included in Phase 1, 18 in Phase 2, and 53 in Phase 3. Additional customers classified as Multiresidential also participated in each phase of customer engagement as shown in Table 1.

Table 1: Number of Apartments

#		Classified as Multiresidential	Classified as Apartment (Account Class)
1	Phase 1	0	2
2	Phase 2	89	18
3	Phase 3	207	53

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 2, Schedule 1, pg. 21

Question(s):

Has EGI recognized the value of investing in distribution system stations to reduce the pressure drop to serve load as opposed to increasing the pipe size?

a) Please describe EGI's views on that assessment as part of IRP.

b) Beyond an IRP pilot, where else has EGI considered this alternative?

Response:

Yes, Enbridge Gas does recognize the value of investing in distribution system stations as an IRP alternative.

a-b) During the detailed design process of a need that is identified on the system, alternatives are assessed including distribution system station impacts, and evaluated for feasibility.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 2, Schedule 1, pg. 21

Preamble:

EGI evidence states: *Other savings were achieved in areas where services were scaled back or no longer needed, processes and procedures were streamlined, and where modes of operational interaction were modified. For example, pandemic-related travel restrictions led Enbridge Gas teams to rely more on virtual interactions in 2020 and 2021, and even with the lifting of restrictions, travel budgets have been reduced.*

Question(s):

Please provide a description what was learned from this evolution.

a) How much does EGI expect to save in office costs in 2024 vs 2019?

b) How much does EGI expect to save in travel costs in 2024 vs 2019?

c) Where would one find these specific savings identified in the evidence?

Response:

Enbridge Gas operates in multiple locations and the use of technology to facilitate meetings was used prior to COVID-19. The pandemic sped up the evolution of the use of technology, including upgrading capability to work from home. With the improvement in technology, Enbridge Gas can now further assess the need to travel for in person meetings, training, conferences, etc. which gives the ability to manage within the Company's travel budget.

a) There were no office cost savings as a result of the pandemic.

b) Travel costs in the 2024 Test Year Forecast are $0.2 million higher compared to the 2019. If EGI factored in inflationary assumptions each year the 2024 Test Year Forecast would have been much higher.

c) These savings have been embedded in the 2024 Test Year O&M Forecast provided at Exhibit 4, Tab 4, Schedule 2, Table 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ginoogaming First Nation (GFN)

Interrogatory

Reference:

Exhibit 1, Tab 2, Schedule 1, p. 3

Preamble:

EGI states that integrity, safety, respect and inclusion, along with its strategic priorities, are values that have guided its decision-making. In addition, EGI noted that the evidence provided in the Application is its business plan and demonstrates how it intends to support customers through continued safe, reliable, cost-effective operations while prudently incorporating new energy solutions.

In its Decision and Order on Enbridge Gas Distribution Inc.'s application for the RNG Enabling Program in EB-2017-0319 dated October 18, 2018, the Ontario Energy Board confirmed that "strategic, higher level decisions can trigger the duty to consult" First Nation communities (p. 25)

Question(s):

a) Please describe and provide evidence for whether — and, if so, how — EGI determined, interpreted, and applied:

   i. its values especially in regard to respect and inclusion;

   ii. the Crown's requirements in respect of reconciliation and honour in engaging with First Nations; and

   iii. the Ontario Energy Board's procedural requirements and decision making considerations; in assisting the Crown in fulfilling its duty to act honourably with the intent to effect reconciliation including through consultation and accommodation impacted First Nation communities in relation to the Application.

Response:

a) For clarity, the complete quote from the Decision and Order on Enbridge Gas Distribution Inc.'s application for the RNG Enabling Program in EB-2017-0319 dated October 18, 2018, is

> "*The OEB accepts that strategic, higher level decisions can trigger the duty to consult. However, in the current case it is not clear that the matters before the OEB have any impact on any identified Aboriginal or treaty right. This Decision approves a rate-setting methodology for an RNG Injection Service and a deferral account under Section 36 of the OEB Act. It does not authorize anyone to build anything. The OEB does not see any direct material impact that this Decision will have on Aboriginal or treaty rights.*"

The current Application before the OEB requests an approval of new base rates and an incentive rate mechanism for the period of 2024 to 2028 and does not authorize Enbridge Gas to build anything. Enbridge Gas is of the view that the Rebasing Application does not trigger the duty to consult. Regardless of whether the duty to consult has been triggered by this proceeding or whether Indigenous consultation is required, Enbridge Gas believes it is appropriate to continue consultation through the OEB-led regulatory consultation process. Enbridge Gas notes that GFN is an active participant in this proceeding before the OEB. Enbridge Gas will address any questions raised by members of Indigenous groups as they arise.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit 1, Tab 2, Sch. 1, para. 24

Question(s):

Please define the term “reasonable rate increases” as used by EGI.

Response:

The Company views the Application as requesting “reasonable rate increases” given that the average rate increase is below inflation and is in the range of what most customers said they would accept.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit 1, Tab 2, Sch. 1, para. 74

Question(s):

Please define the term “a more effective utility” as used by EGI.

Response:

A more effective utility is one that can deliver safe, reliable and efficient business operations and respond to customer needs and future market evolution. Enbridge Gas builds on the success of its predecessor organizations, delivering extensive integration benefits as provided at Exhibit 1, Tab 9, Schedule 1. Please also see response at Exhibit I.1.9-CCC-25.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Otter Creek Co-operative Homes Inc. (Otter Creek)

Interrogatory

Question(s):

Programs and services for low-income households

a) Please set out what EGI's services for low-income households will be.

b) Please provide any Canadian evidence, studies or surveys that EGI has with respect to its current services and programs for low-income households, specifically with respect to maintaining services.

Response:

a) There is no reference to evidence provided in this interrogatory, it is therefore unclear what specific services are being referenced. To be responsive the Company provides the following:

   i. With regard to DSM programming, the Company received approval in the 2022-27 Multi-year DSM Plan Decision[1] for over $70 million in funding over the three-year 2023-2025 period which includes DSM programs tailored to support lower income consumers across the Enbridge Gas franchise. The Low-Income Program includes a set of program offerings designed for low-income residents of single and multi-residential housing, both social housing and privately owned, aimed at improving the energy efficiency of targeted buildings and helping these residents manage their natural gas bills.

   ii. Enbridge Gas offers the Low-Income Energy Assistance Program (LEAP) to customers who are in arrears and at risk of being disconnected. United Way Simcoe Muskoka administers the LEAP program across the Enbridge Gas franchise. United Way Simcoe Muskoka reviews low-income eligibility with customers who apply and under the current LEAP rules, may approve emergency financial assistance of up to $1,000 to a customer's arrears balance.

[1] EB-2021-0002, Decision and Order, November 15, 2022.

b) Enbridge Gas periodically conducts studies and surveys specifically in support of the Low-Income DSM Program, including a survey to collect feedback from recent participants. These surveys and studies were in scope in the recent Application for Multi-Year Natural Gas Demand Side Management Plan[2] (2022 to 2027) proceeding. Issues around DSM programming are not part of this proceeding.

[2] EB-2021-0002

ENBRIDGE GAS INC.

Answer to Interrogatory from
Otter Creek Co-operative Homes Inc. (Otter Creek)

Interrogatory

Question(s):

EGI is tasked by the Federal Government of Canada to help Canadians lower their energy bills and make their homes more energy efficient. Has EGI factored into this application the impact this program will have on the demand for natural gas services?

Response:

Enbridge Gas interprets the question to be asking about the impact of the recently introduced Home Energy Rebate Plus ("HER+") Program that is being jointly funded by Enbridge Gas and Natural Resources Canada ("NRCan"). HER+ was introduced in January 2023. Any potential impacts on the Ontario market will not be reasonably determined until sufficient time in the market has been reached, estimated to be at minimum a full year.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Otter Creek Co-operative Homes Inc. (Otter Creek)

Interrogatory

Question(s):

If the demand for nature gas is reduced due to natural gas consumption, this will reduce EGI's profits. At what rate will this loss of profits determine increases to end users.

Response:

Enbridge Gas does not agree with the statements made as part of this question, specifically, that a reduction in natural gas demand and consumption will always result in a reduction in profits, or that a loss in profits will result in or determine rate increases to end users. For instance, where rates are designed to reflect a decline in consumption, or where there are volumetric protection mechanisms (for ratepayers and or Enbridge Gas) in place (i.e. deferral account mechanisms), a decline in consumption does not translate into a loss in profits. In addition, a loss in Enbridge Gas profits does not necessarily or immediately translate into an increase in rates to consumers. Approved rates simply provide Enbridge Gas with the opportunity to earn a regulated rate of return (profit). Statements such as those made in this question would need to be made in the context of specific circumstances or assumptions.

In this proceeding, Enbridge Gas is requesting approval for 2024 rates established using a cost of service methodology, as well as approval of an incentive rate setting mechanism for 2025 – 2028. Under cost of service, Enbridge Gas is looking to establish 2024 rates that will allow it to recover its forecast of costs (inclusive of an allowed return on equity, or profit) to provide regulated distribution, transmission and storage services. In order to design rates to recover those costs, Enbridge Gas has also provided its latest forecast of demand (or consumption), inclusive of any forecast demand changes (decreases and or increases). Using a current forecast of volumes should reduce the risk of profit variability due to demand decreases or increases (because any anticipated demand changes would have been reflected in rates). In addition, Enbridge Gas is also proposing a Volume Variance Account to capture the revenue, net of gas cost, impacts attributable to actual versus forecast general service volumetric variances resulting from weather and average use differences. These mechanisms combined will largely protect ratepayers (from Enbridge Gas earning higher profits) and the Company (from lower profits) from impacts attributable to volumetric variability.

Enbridge Gas also notes that as part of this Application it is also requesting approval to implement Straight Fixed Variable with Demand (SFVD) rate design to harmonized general service rates classes, effective April 1, 2025. If approved, the use of SFVD rate design would see fixed costs recovered through fixed charges and variable costs recovered through volumetric charges, as compared to the traditional volumetric rate design currently employed for general service rate classes, where costs are recovered through the combination of a monthly customer charge and volumetric delivery charges. The current recovery of fixed charges (inclusive of the return on equity) through both fixed and volumetric charges can result in variability in profits (lower and higher) when demand is lower or higher than forecast. As such, one of the benefits of SFVD rate design is that it largely eliminates variability in the recovery of fixed charges and eliminates the need for associated deferral accounts.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association (QMA)

Interrogatory

Reference:

Ref: E1/T2/S1/p.2

Question(s):

Enbridge states in the Executive Summary for the Application that its customers "…are an integral part of Enbridge Gas's business planning and decision-making processes, and their feedback, gathered through extensive engagement, directly informs this rate rebasing application…". Please confirm that customer engagement activity covers/includes customers in all rate classes across the entire Enbridge service territory in Ontario.

Response:

Customer engagement covers customers across the entire franchise area. The customer engagement focused on customers in rate classes with proposed changes to services and as such, included most rate classes with the exception of those rate classes with limited proposed changes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-2-1 p.9, 21

Question(s):

Enbridge states: "[R]egardless of the direction of Ontario's energy transition, the natural gas system will be critical to providing Ontarians with resilient, reliable, cost-effective energy solutions, including by working in a more integrated way with the electricity system." Please confirm that the Application is premised on the Enbridge's statement being true, and on the assumption that no significant reduction in the total demand for natural gas in Ontario is likely during the next ten years. If this is not confirmed, please explain.

Response:

Enbridge Gas's Application is based on the premise that, over the course of the 2024 to 2028 rebasing term, regardless of the direction of Ontario's energy transition, the natural gas system will be critical in providing Ontarians with resilient, reliable, cost-effective energy solutions, including by working in a more integrated way with the electricity system. In addition, Enbridge Gas notes that its Application is based on the premise that, over the course of the 2024 to 2028 rebasing term, the design hour and design day demand will not have a significant reduction.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-2-1, p.10

Question(s):

Please provide Enbridge's best estimate of the amount, by which 2022 natural gas throughput was lower, as a result of the cumulative impact of the Enbridge's DSM programs over time.

Response:

The Company notes that this response is provided on a best-efforts basis to be responsive to the question as posed.

Measures that were implemented as a result of DSM programs and have persisting savings in 2022 are estimated to have reduced gas consumption in 2022 by 2.72 billion m^3. This figure is based on totaling the net annual natural gas savings for the span of the average effective useful life across all measures, based on the measure mix in the 2021 program year.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-2-1, p.12

Question(s):

Please confirm that at no time during the stakeholdering of this Application did Enbridge, or its consultants, tell customers that they would be responsible for paying the cost of any new or existing assets stranded due to the energy transition.

Response:

Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-2-1, p.15

Question(s):

Please provide any studies, documents, presentations or other evidence showing that hybrid heating systems will continue to be cost-effective for customers throughout the expected life of the assets.

Response:

Please see response at Exhibit I.10h.EGI.STAFF.77 from the 2022-2027 DSM Plan proceeding[1], which provides lifecycle cost comparisons of hybrid heating systems with smart controls to those of all-electric solutions for two archetype homes in Toronto, Ontario.

In addition, please see the case studies below from the Sustainable Technologies Evaluation Program by the Toronto and Region Conservation Authority, where even without smart controls, hybrid heating is demonstrated as being cost-effective in the long run, as the cost of carbon is projected to increase over time:

i. Residential Heat Pump Case Study 1: Hybrid Heating in a Semi-Detached House[2]

ii. Residential Heat Pump Case Study 2: Low-Cost Hybrid Heating in a Toronto Home[3]

iii. Residential Heat Pump Case Study 3: Hybrid Heating in a Toronto Century Home[4]

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[1] EB-2021-0002.
[2] https://sustainabletechnologies.ca/app/uploads/2021/12/HP_Case_Study_1.pdf
[3] https://sustainabletechnologies.ca/app/uploads/2021/12/HP_Case_Study_2.pdf
[4] https://sustainabletechnologies.ca/app/uploads/2021/12/HP_Case_Study_3.pdf

One of the benefits of a hybrid heating system is that the smart controller can be programmed to use the least cost energy for heating at any point in a year. The utility costs may change over the lifetime of the equipment, and this information can be programmed into the controller to maintain the energy affordability of the system. These controllers use many variables in the control algorithm such as: outdoor temperature, COP curve of heat pump, efficiency of furnace, TOU electric price, and natural gas cost.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-2-1, p.15

Question(s):

Please confirm that the $200 million advantage between now and 2050, of the Applicant's preferred transition, can only be achieved if the natural gas distribution infrastructure currently in service, or brought into service during the current planning period, remains used and useful throughout its expected life.

Response:

Confirmed. The referenced $50 billion (not million as referenced in the question) cost /u
advantage is the approximate difference in costs between the lower cost Diversified /u
pathway sensitivities and the Electrification pathway presented in the Pathways to Net- /u
Zero Emissions for Ontario (P2NZ) Report, provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2. The P2NZ Report concluded that "a diversified approach that includes a targeted approach to electrification tied with deployment of low- or zero-carbon gases, including renewable natural gas (RNG), hydrogen, and natural gas with carbon capture, is the most cost-effective and resilient method to achieve net zero emissions in
Ontario."[1] The $50 billion cost advantage is based on the assumption that the gas /u
distribution infrastructure in the province remains used or useful; transitioning over time to provide resiliency and to support the province's GHG emissions reductions targets by delivering low- or zero-carbon gases, as well as natural gas to end-users where carbon capture is used.

[1] Exhibit 1, Tab 10, Schedule 5, Attachment 2, Page 3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-2-1, p.16

Question(s):

Enbridge states: “Energy transition planning is not only reflected in the Company’s “safe bet” actions, but also in the way Enbridge Gas is forecasting growth, managing risk and allocating capital.” Please provide an estimate of Enbridge’s total rate base each year until 2033, and provide details explaining how this estimate has been altered from what it would have been, absent the claim made in the above quote.

Response:

Total rate base forecasted for years 2024 to 2026 are provided in Table 1.

Table 1
2024-2026 Rate Base

($ millions)	2024	2025	2026
Rate base	16,281 (as filed in Exhibit 2, Tab 1, Schedule 1, Page 5, Updated March 8, 2023)	16,739	17,236

Enbridge Gas does not have a forecast of rate base for 2027 to 2033 as the Company’s latest long-range plan extends to 2026.

Enbridge Gas does not currently have a forecast of asset plans without energy transition planning (with the exception of customer connections capital expenditure – please see response at Exhibit I.2.6-STAFF-72) and therefore, forecasted rate base absent impacts from energy transition planning is not available. Energy Transition is inherent in Enbridge Gas’s planning as described in Exhibit 1, Tab 10, Schedule 4 and based on its embedded and pervasive nature, Enbridge Gas would be unable to completely remove the impact of energy transition, especially given the complexity within the capital budget process (please see Exhibit 2, Tab 6, Schedule 1, Section 3.4). Unwinding energy transition impacts would mean that the 10-year AMP would need to be rebuilt; for instance, network hydraulic models would have to be updated for each of the 10 years to understand the need for growth projects or IRP projects. Cost estimates would then have to be produced for each alternative. Based on the level of effort required to undertake this exercise with energy transition assumptions considered, it would take several months of additional work to produce.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-2-1

Question(s):

Please provide a copy of all material provided to Enbridge Inc. for approval of the application and the underlying budgets.

Response:

Please see the following documents that were provided to Enbridge Inc. for approval of the Application and underlying Budget:

Attachment 1 – 2023 Budget and LRP Review presentation
Attachment 2 – 2024 Rebasing Proposal Approval presentation

GDS DRAFT
2023 Budget & LRP Review

October 28th 2022

ENBRIDGE

Key Assumptions / Executive Summary

ENBRIDGE

Executive Summary

- GDS EBITDA average growth of 7.03%, achieving EBITDA in all years mainly due to Price Cap Index and recovery of deficiency in 2024
- GDS achieving DCF target in all years due to strong EBITDA overcoming Maintenance Capital pressures

Assumptions

- 2023 Budget Assumptions include:
  - PCI 3.6% (PCI = 2021 Actual GDP IPI FDD (3.9%) – Productivity (0%) - Stretch (0.3%))
  - Achieved ROE of 9.7%, Board Approved ROE 8.66%. ESM Gap at $35M.
- 2024 is a rebasing year and assumed to be Cost of Service, with all CTA recovered and earning Board Approved ROE
- 2025 and 2026 assumes earning Board Approved ROE

GDS Plan Review

ENBRIDGE

(CAD millions[1], except for percentages)	2021A	2022F (2+10F)	2023B	2024 LRP	2025 LRP	3 Year CAGR (2022-2025)	Comments
Revenue	**2,943**	**3,024**	**3,112**	**3,395**	**3,546**	**5.44%**	Growth due to PCI, Customer Growth, rebasing rate increase in 2024 carrying through LRP as we earn Board Approved ROE with increased equity thickness and depreciation proposal
YoY%		3%	3%	9%	4%		
Operating Expenses *	**1,089**	**1,154**	**1,178**	**1,224**	**1,252**	**2.77%**	Central function decrease in 2023 due to insurance premium reduction, pension & benefits. CF increasing throughout rest of plan. Merit & inflation and DSM (offset by increasing revenue) increasing throughout rest of plan
YoY%		6%	2%	4%	2%		
EBITDA	**1,853**	**1,870**	**1,934**	**2,171**	**2,293**	**7.03%**	Increasing EBITDA due to drivers above
YoY%		1%	3%	12%	6%		
BU DCF	**1,580**	**1,491**	**1,602**	**1,724**	**1,868**	**7.80%**	DCF growth driven by increasing EBITDA at faster rate than Maintenance Capital throughout plan
YoY%		-6%	7%	8%	8%		
Growth Capital	**963**	**1,143**	**1,425**	**1,183**	**1,181**	**1.11%**	System reinforcement, Dawn C compression, Dawn to Parkway Expansion throughout plan adding to strong rate base growth
YoY%		19%	25%	-17%	0%		
Maint. Capital	**273**	**380**	**333**	**448**	**425**	**3.81%**	Higher REWS, Compression stations, meter purchases throughout plan adding to strong rate base growth
YoY%		39%	-12%	35%	-5%		
CTA Capital	**88**	**42**	**44**	**-**	**-**		Integration projects leading to high CTA capital during deferred rebasing term, ending in 2023
YoY%		-52%	5%	-	-		
Free Cash Flow (EBITDA less all Capital)	**530**	**306**	**133**	**540**	**687**	**30.91%**	Strong EBITDA growth due to rebasing rate increase in 2024 carrying through LRP, relative to Growth Capital and no CTA in 2024 and 2025 leading to strong free cash flow in 2025
YoY%		-42%	-57%	307%	27%		

Note: Operating Expenses includes Central Functions

EBITDA/DCF Bridge (2023 Budget vs 2022 2+10F)

ENBRIDGE

Segment	2023 Budget	2022 2+10F	Total Variance *(A)*	Variance due to CF *(B)*	Business Drivers *(A-B)*	Variance Explanation (Quantified if possible)
Distribution Margin	2,471	2,361	110	-	110	PCI +80M, Customer Growth +20M, ICM - Lakeshore KOL and St Laurent P3 +22M, Acc CCA - CTA projects reversing +10M, DSM +9M, Gas Supply Margin/Fuels due to lower UFG and UAF true up +5M, CM +3M, CPT +1M, Comm. Exp. +2M, APCDA due to higher capitalization rates and depreciation change -17M, Weather -27M
S&T Revenue	437	448	(11)	-	(11)	LT Transport due to Turnback -6M, LT Storage optimization due to higher mitigation costs in 2023 -12M, LT Storage price -2M, partially offset by PCI +5M, FX +4M
O&M	1,168	1,133	(35)	-	(35)	Merit & Inflation -18M, Self Insurance -13M, Property Tax due to higher inflation assumption -5M, Bad Debt -5M, DSM -10M, Ops – Locates/Lakeside/Crossbore -7M, Donations -3M, Rebasing consultant -2M, Finance & Other BU support costs -3M; partially offset by 1% Budget savings commitment +8M, higher Capitalization +24M (BU+9M, CF +15M)
Other	139	148	(9)	(4)	(5)	Discontinuing open bill -5M
EGI EBITDA	**1,879**	**1,824**	**55**	**(4)**	**59**	
Other GD EBITDA	55	46	9	1	8	Niagara RNG +3M, Lakeside +4M, Combined Heat and Power Plant sales +1M, Project Trafalgar +1M, partially offset by Gazifere -1M
GDS EBITDA	**1,934**	**1,870**	**64**	**(3)**	**67**	
Maintenance Capital	333	380	**47**	**-**	47	REWS +45M, +8M lower Compression Stations due to Crowland Station Renewal ending in 2022; higher Meter purchases -7M
Equity Dividends in excess of Equity Earnings	1	1	**-**	**-**	-	
Total DCF	**1,602**	**1,491**	**111**	**(3)**	**114**	
EBITDA (from above)	1,934	1,870	64	(3)	67	
Depreciation	784	772	**(12)**	**-**	**(12)**	Panhandle Regional Expansion Project, Dawn to Corruna, addition of TIS assets, increased overheads, lower ACDA amortization
GDS EBIT	**1,150**	**1,098**	**52**	**(3)**	**55**	

EBITDA/DCF Bridge (2023 Budget vs 2023 PY LRP)

Segment	2023 Budget	2023 LRP	Total Variance (A)	Var. due to CF (B)	Business Drivers (A-B)	Variance Explanation (Quantified if possible)
Distribution Margin	2,471	2,412	59	-	59	PCI +49M, return on carrying costs of gas inventory +10M, ICM +10M, Gas Supply Margin/Fuels +7M; APCDA -9M, Acc CCA -9M
S&T Revenue	437	424	13	-	13	Storage price +6M, higher LT Transport +4M, ST transport +4M, PCI +3M; Storage optimization due to higher mitigation costs -7M
O&M	1,169	1,110	(59)	(36)	(23)	Inflation -22M, Self Insurance -13M, Integrity -9M, Ops – Locates/Lakeside/Crossbore -7M, Bad Debt -6M, additional Merit -2M; 1% Budget savings commitment +8M, higher Capitalization +31M (BU+17M, CF +14M)
Other	140	124	16	13	3	
EGI EBITDA	**1,879**	**1,850**	**29**	**(23)**	**52**	
Other GD EBITDA	55	53	2	1	1	
GDS EBITDA	**1,934**	**1,903**	**31**	**(22)**	**53**	
Maintenance Capital	333	312	**(21)**	**-**	(21)	TIS -24M, higher meter purchases -3M, accumulation of Other small projects -13M; REWS +10M, lower Compression Stations +4M
Equity Dividends in excess of Equity Earnings	1	1	**-**	**-**	-	
Total DCF	**1,602**	**1,592**	**10**	**(22)**	**32**	
EBITDA (from above)	1,934	1,903	31	(22)	53	
Depreciation	784	809	**25**	**-**	**25**	Lower software depreciation due to higher retirements in 2021 reflected in 2023 Budget, removal of GDS Oracle Cloud Project (included in PY LRP), lower ACDA amortization
GDS EBIT	**1,150**	**1,094**	**56**	**(22)**	**78**	

- Other includes Other Revenue, Other Income/Expense, and L25104 EBITDA

Capital Bridge (2023 Budget vs 2023 PY LRP)

ENBRIDGE

2023 PY Capital LRP	Category	1,518	Variance Explanations (+ increase, - decrease)
Maintenance Capital	MC	20	+24M TIS, +3M higher meter purchases, +7M accumulation of Other small projects; -10M REWS, -4M lower Compression Stations
Growth	Growth	269	+23M Increase in Dawn to Corunna, +71M Panhandle Expansion, +35M higher Distribution Pipe, +44M higher Distribution Stations, +15M higher Transmission Pipe and Underground Storage, +70M higher Unregulated Storage and RNG projects, +3M BioRefinx RNG, +4M Other
Integration Capital (CTA)	MC	(7)	Cancellation of Building System Management Solution, removal of GDS Oracle Cloud costs, Site 2 & 3 (East & West), and AWS costs for phase 3 not being identified in last year's LRP.
2023 CY Capital Budget		**1,800**	

Key Message: MC pressures due to TIS and REWS. Increasing Growth Capital significantly due to Panhandle Expansion, Crowland Storage Transfer and Lisgar station, higher RNG.

EBITDA/DCF Bridge (2024 CY LRP vs 2024 PY LRP)

ENBRIDGE

Segment	2024 CY LRP	2024 PY LRP	Total Variance (A)	Var. due to CF (B)	Business Drivers (A-B)	Variance Explanation (Quantified if possible)
Distribution Margin	2,880	2,524	356	-	356	Gas Supply Margin/Fuels primarily due to removal of LEGD LT Transport contract leading to cost savings (offset in reduction to S&T rev) +145M, Deficiency rate adj. +179M (242M CY plan vs 63M PY), PCI +49M (from 2023), return on carrying costs of gas inventory +10M, Comm. Exp. +2M, higher fuels due to new UFG methodology and reduction of CSF from LEGD contracts -25M, PDCI costs -4M, ICM -1M
S&T Revenue	311	440	(129)	-	(129)	Lower LT Transport primarily due to LEGD Contracts going away -142M, Storage optimization -4M; Storage price +4M, RNG injection station (PY budget in Other Revenue) +4M, PCI +3M, ST transport +3M
O&M	1,213	1,124	(89)	(70)	(19)	Inflation -16M, Integrity -11M, Ops – Locates/Lakeside/Crossbore -10M and Self Insurance Reserve -10M, Bad Debt -7M, additional Merit -6M; higher Capitalization +32M (BU+11M, CF +21M), 1% Budget savings commitment +12M
Other	133	127	6	17	(11)	Discontinue Open bill program -22M (partially offset by 12M O&M savings), RNG injection station (CY LRP in S&T) -5M; increase in LPP +7M, increase from various services revenues +4M
EGI EBITDA	**2,111**	**1,967**	**144**	**(53)**	**197**	
Other GD EBITDA	60	55	5	1	4	
GDS EBITDA	**2,171**	**2,022**	**149**	**(52)**	**201**	
Maintenance Capital	448	352	**(96)**	**-**	(96)	Higher OH Allocation -24M, higher Transmission Pipe and Storage -23M, higher REWS -22M, higher TIS -21M, higher Meter purchases -21M, higher Fleet & Equipment -9M, Rockcliffe Project Increase -7M; lower Compression Stations +29M
Equity Dividends in excess of Equity Earnings	1	1	**-**	**-**	-	
Total DCF	**1,724**	**1,671**	**53**	**(52)**	**105**	
EBITDA (from above)	2,171	2,022	149	(52)	201	
Depreciation	985	851	**(134)**	**-**	**(134)**	Impacts of new depreciation study for rebasing, higher overall capital plan; partially offset by GDS Oracle Cloud included in PY LRP but removed in CY
GDS EBIT	**1,186**	**1,171**	**15**	**(52)**	**67**	

Proposed Deficiency Drivers

ENBRIDGE

In $ millions

Net sustainable synergies and productivity	(67)
Changes in accounting policy and methodologies	(26)
Impact related to ICM and Capital Pass Through projects	42
Deferred Rebasing Impact	**(51)**
Cost pressures	69
Depreciation	198
Equity thickness	26
Cost of Service Impacts	**293**
Total Delivery Revenue Deficiency	**242**
Gas Supply Deficiency	**23**
Total Deficiency	**265**
Total Revenue Requirement	6,279
Deficiency as a % of Revenue Requirement	4%

Capital Bridge (2024 CY LRP vs 2024 PY LRP)

ENBRIDGE

2024 PY Capital LRP	Category	1,520	Variance Explanations (+ increase, - decrease)
Maintenance Capital	MC	95	+21M higher TIS, +22M higher REWS,+21M higher Meter purchases and Regulator Refit replacements, +23M higher Transmission Pipe and Storage, +24M higher OH Allocation, +9M higher Fleet & Equipment, +7M Rockcliffe Project Increase; -29M lower Compression Stations -3M Other.
Growth	Growth	15	+38M higher Transmission Pipe & Underground Storage due to Panhandle expansion project and Dawn parkway Expansion project, +16M higher Customer Connections, +5M higher System Reinforcement; -31M lower Distribution Pipe, -7M lower Distribution Station, -6M lower Meter purchases
Integration Capital (CTA)	MC	-	No integration capital starting in 2024
2024 CY Capital LRP		**1,630**	

Key Message: MC DCF pressures due to higher TIS, higher REWS, higher overheads, and higher meter purchases. Growth consistent with PY LRP.

EBITDA/DCF Bridge (2025 CY LRP vs 2025 PY LRP)

Segment	2025 CY LRP	2025 PY LRP	Total Variance (A)	Var. due to CF (B)	Business Drivers (A-B)	Variance Explanation (Quantified if possible)
Distribution Margin	3,024	2,555	469	-	469	Gas Supply Margin/Fuels primarily due to removal of LEGD LT Transport contract leading to cost savings (offset in reduction to S&T rev) +145M, PCI +131M*, deficiency rate adj. +182M**, return on carrying costs of gas inventory +10M, CM +5M, PDO/CPT rate var. +3M, storage allocation rate var.+3M, Comm. Exp. +2M, higher fuels due to reduction of CSF from LEGD contracts -11M, PDCI costs -4M
S&T Revenue	311	440	(129)	-	(129)	Lower LT Transport primarily due to LEGD Contracts going away -142M, Storage optimization -4M; RNG injection station (PY budget in Other Revenue) +5M, PCI +4M, ST transport +3M, Storage price +1M
O&M	1,242	1,132	(110)	(82)	(28)	Integrity -11M, inflation -10M, Ops – Locates/Lakeside/Crossbore -10M and Self Insurance Reserve -10M, Bad Debt -7M, addit. Merit -6M, higher Property Tax due to higher inflation assumption. -4M, Travel -1M; higher Capitalization +31M (BU+8M, CF +23M)
Other	137	132	5	21	(16)	Discontinue Open bill program -23M (partially offset by 12M O&M savings), Construction Heat Meter Activation -1M; increase in LPP +7M, increase from various services revenues +3M
EGI EBITDA	**2,230**	**1,995**	**235**	**(61)**	**296**	
Other GD EBITDA	63	57	6	1	5	
GDS EBITDA	**2,293**	**2,052**	**241**	**(60)**	**301**	
Maintenance Capital	425	332	**(93)**	**-**	(93)	Higher OH Allocation -44M, higher Meter purchases -27M, higher REWS -21M, higher TIS-17M, higher Fleet and Equipment -9M; lower Unregulated Storage Enhancement projects +13M, lower Compression Stations +8M
Equity Dividends in excess of Equity Earnings	-	1	**(1)**	**-**	(1)	
Total DCF	**1,868**	**1,721**	**147**	**(60)**	**207**	
EBITDA (from above)	2,293	2,052	241	(60)	301	
Depreciation	1,028	849	**(179)**	**-**	**(179)**	Impacts of new depreciation study for rebasing, increase in TIS assets PvP
GDS EBIT	**1,265**	**1,203**	**62**	**(60)**	**122**	

*PCI +131M due to higher PCI from 2023 and PCI of 3.04% in 2025 vs none in PY LRP
**Deficiency rate adjustment = (242M 2024 Distribution deficiency – 7M DSM) * 3.04% PCI + 14M Equity Thickness – 6M Productivity Update =249M – 67M deficiency in PY LRP = +182M

Capital Bridge (2025 CY LRP vs 2025 PY LRP)

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2025 PY Capital LRP	Category	1,831	Variance Explanations (+ increase, - decrease)
Maintenance Capital	MC	94	+44M higher OH Allocation, +27M higher Meter purchases and Regulators refit, +21M higher REWS, +17M higher TIS, +9M higher Fleet and Equipment; -13M lower Unregulated Storage Enhancement projects, -8M lower Compression Stations, -3M Other.
Growth	Growth	(317)	-93M lower Distribution Pipe, -64M lower System Reinforcement, -131M lower Transmission Pipe & Underground Storage, -53M lower Compression Stations, -8M lower Meter purchases; partially offset by +17M higher Customer Connections, +8M higher Distribution Station, +4M Gazifere, and +3M Other.
Integration Capital (CTA)	MC	-	
2025 CY Capital LRP		**1,607**	

Key Message: MC pressures due to higher OH's, TIS, REWS, and higher meter purchases. Growth Capital decrease due to removal of Vintage Steel Replacement, reduction to Owen Sound Transmission, Marten River Compression, and Rideau Reinforcement, reduced D-P expansion and lower Dawn C spend

Key Sensitivities

Segment	Asset	Description	DCF Impact – '23 Budget	DCF Impact – CY '24 LRP	DCF Impact – CY '25 LRP
EGI	All	2024 Rebasing	-	?	?
EGI	All	Energy Transition	?	?	?
EGI	Utility	ROE: 10 basis point change in ROE (based off 36% equity thickness)	+/- 7	+/- 7	+/- 7
EGI	Utility	Equity Thickness +1% change	-	+/-14	+/-14
EGI	Revenue	10 basis point change in PCI	+/- 2	+/- 2	+/- 2
EGI	Dist. Margin	Weather 5% change in HDD's	+/-38	+/-38	+/-38
EGI	Dist. Margin	Contract Market: 10% change in throughput (Fixed Revenue 80% for EGI)	+/- 5	+/- 5	+/- 5
EGI	Dist. Margin	10% Change in Ref. Price Impact on Return on Carrying Cost GIS (based off April QRAM)	+/- 3	+/- 3	+/- 3
EGI	Dist. Margin	+/- 3,000 Change in Customers	+/- 2	+/- 2	+/- 2
EGI	S&T	Storage Revenue: $0.1 US/mmbtu change in Storage price	+/- 1	+/- 8	+/- 15
EGI	O&M	Additional 1% of inflation/CPI than currently in Plan	+/- 5	+/- 5	+/- 5
EGI	O&M	Inflation/Market Conditions impact on Customer Care/ Bad Debt	?	?	?
Total Tailwinds/Headwinds Impact			**~+/-63**	**~+/-84**	**~+/-91**

Assumptions

Assumptions	Proposal			
Year	**2023**	**2024**	**2025**	**2026**
Board Approved ROE	8.66%	8.66%	8.66%	8.66%
FX Rate	1.25	1.25	1.25	1.25
Debt/Equity	64/36	62/38	61/39	60/40
Merit	4%	5%	3%	3%
Inflation *	2.4%	2.2%	2%	2%
GDP IPI FDD	3.9%	N/A	2%	2%
Productivity	0%	N/A	-1.04%	-1.04%
Stretch	0.30%	N/A	0%	0%
PCI (GDP IPI FDD less Productivity less Stretch)	3.6%	N/A	3.04%	3.04%
Customer Growth	39,377	37,624	37,624	37,624

* Only applicable to small portion of O&M. Majority is based off bottoms up approach where known costs are used and not an assumption. Effective inflation rate inherent in O&M budget 5.4% for 2023, 2.4% for 2024

Enbridge Gas
2024 Rebasing Proposal

ENBRIDGE
Life Takes Energy

September 15, 2022

Purpose

Today:

- Review and Approve Rebasing Proposal with President and CEO, Enbridge Inc. and SVP and President, Gas Distribution and Storage
- Rebasing Filing timeline

Agenda

- What will success look like?
- Energy context and affordability
- Meeting the Filing Guidelines
  - O&M
  - Capital invested since last rebasing and 2024 capital additions
  - Capital structure
  - Depreciation
  - Productivity and stretch factors
- Energy Transition context
- Rate and Service Harmonization and Implications for Regulatory Timelines

Rebasing and Incentive Rate Mechanism

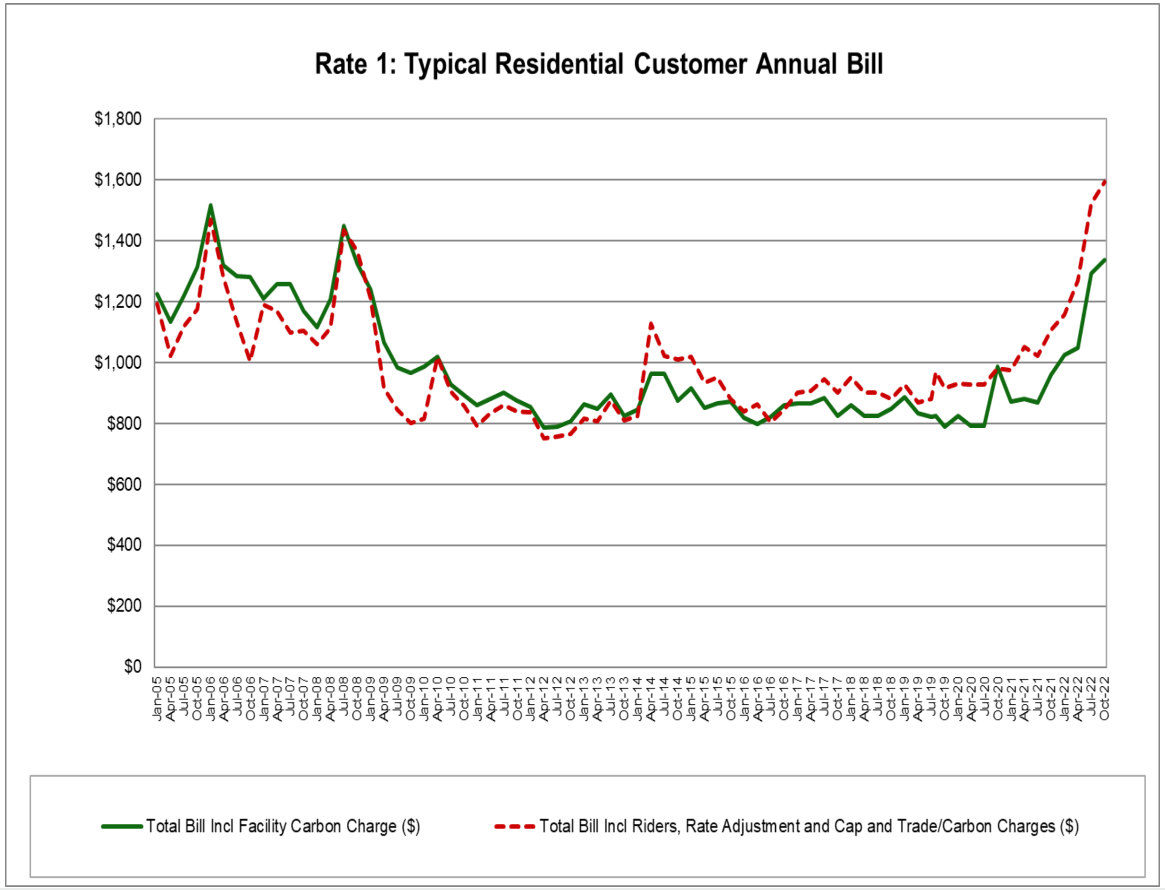
Success measures:

- 2024 rates in place Jan 1, 2024
- 2024 base rates and 2024-2028 incentive mechanism balance customer and shareholder needs
- Energy Transition impacts on business risk mitigated
- Harmonized rates and services across province deliver the “Enbridge” experience to customers

Enbridge is the first major utility to file a post amalgamation rebasing application under the OEB MAADs framework

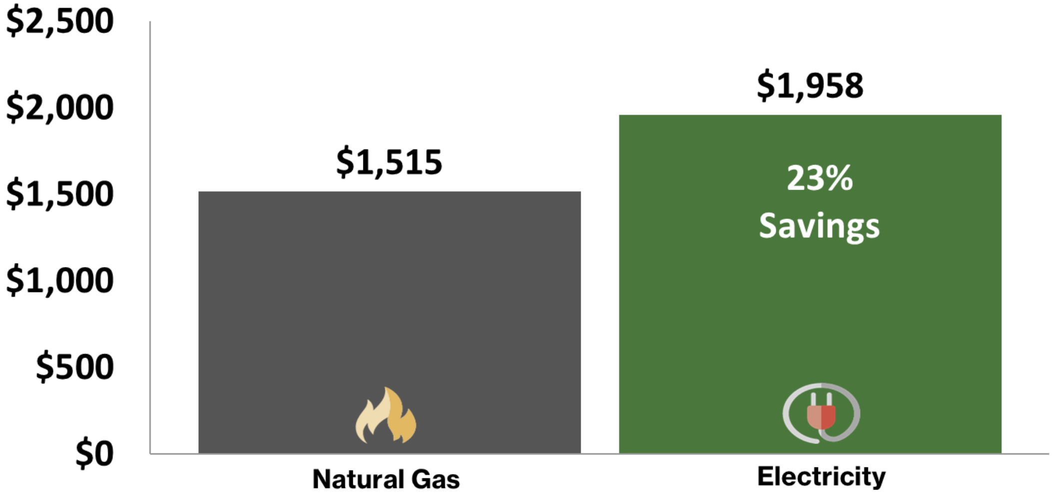
Current Energy Environment

Gas bills at all time highs



Natural gas price advantage declining

Average Residential Annual Heating Bills

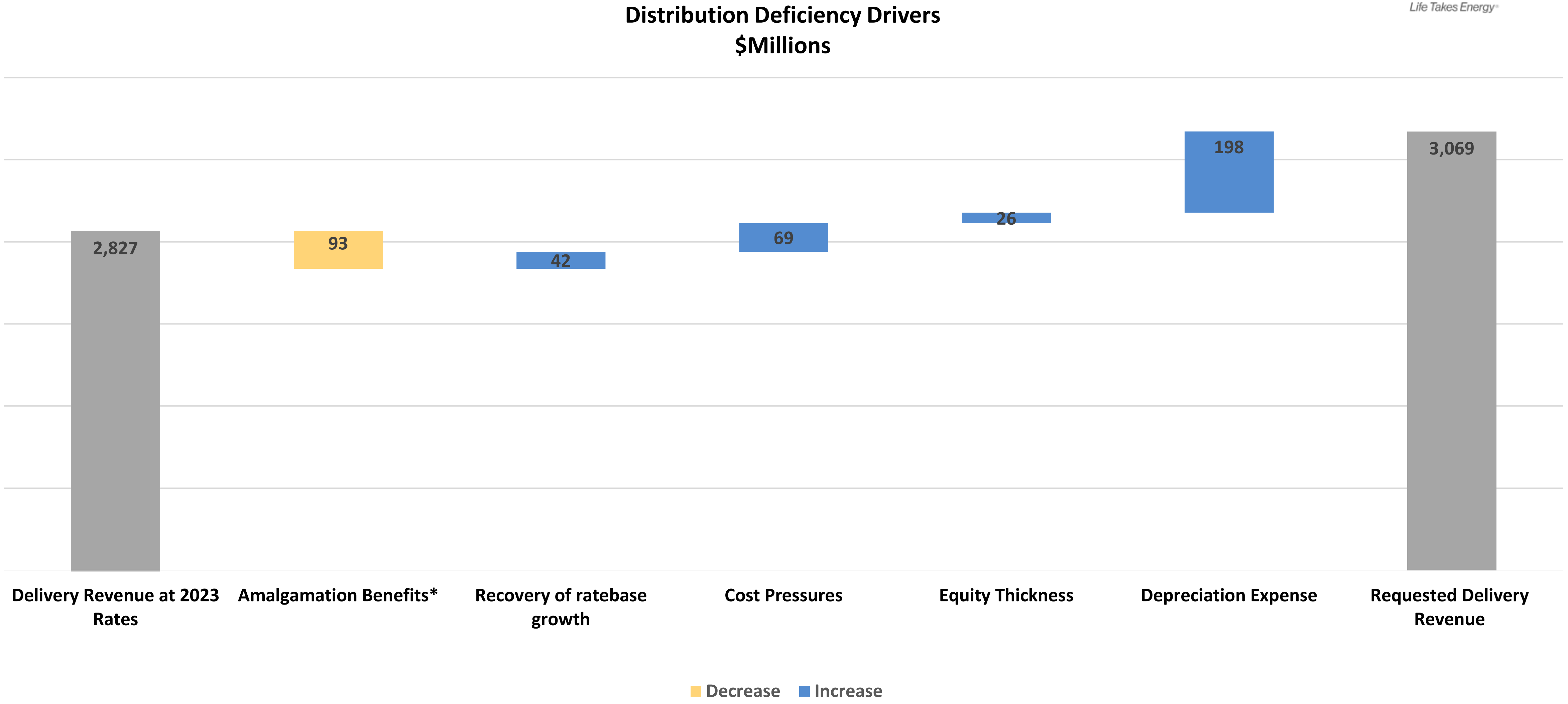


*Average of Rate 1 & Rate M1

Notes: Natural gas prices are based on rates in effect as of **October 1, 2022.** Electricity rate based on Toronto Hydro and London Hydro rates as of **May 1, 2022** and RPP customers that are on TOU pricing. It includes the new Ontario Electricity Rebate (OER). Costs have been calculated for the equivalent energy consumed and include all service, delivery and energy charges. Carbon price is included for all energy types as reported. HST is not included.

Energy affordability, all time high gas bills and escalating carbon prices limit increases in delivery prices

2024 Draft Revenue Deficiency



8.6% increase in distribution revenue reflects a 4% average customer bill impact

Notes:
*Amalgamation Benefits includes synergies, productivity, accounting policy harmonization and recovery of Net Book Value of integration costs

Earnings 2019-2024

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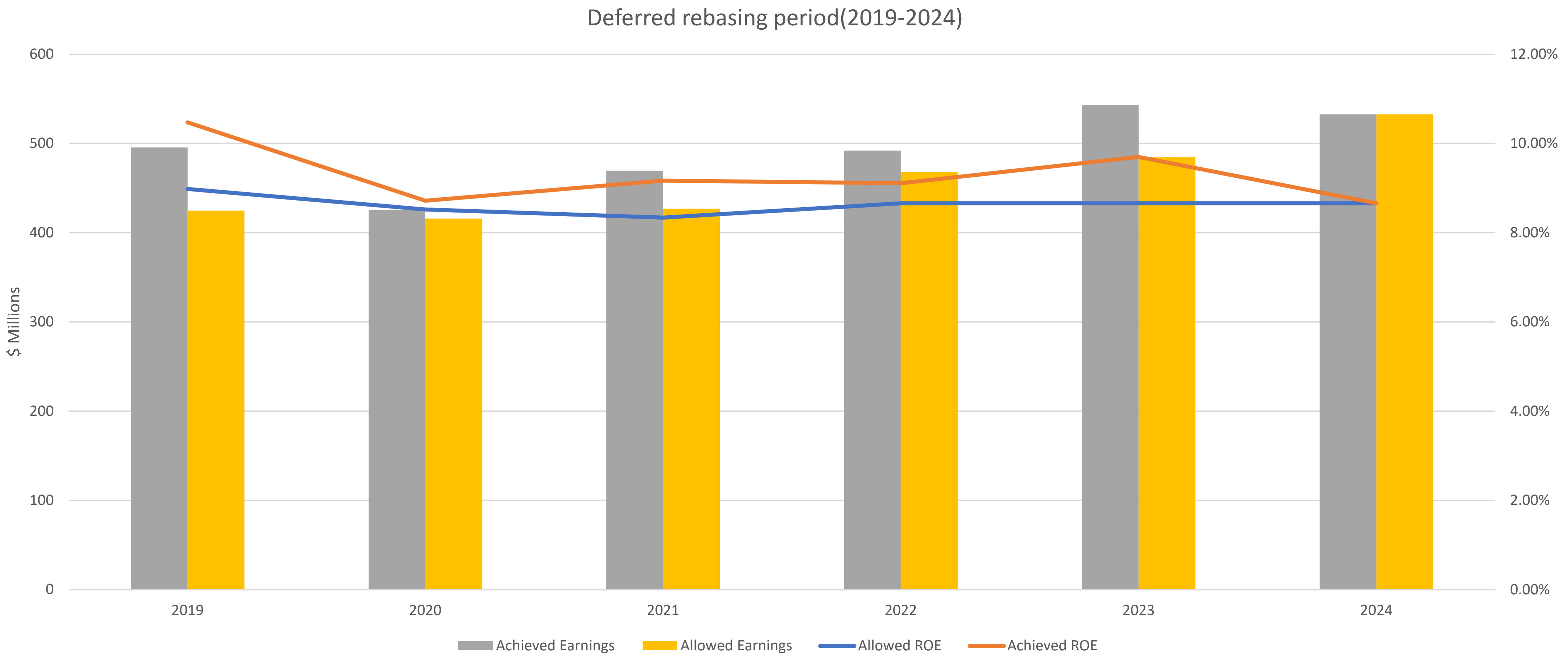
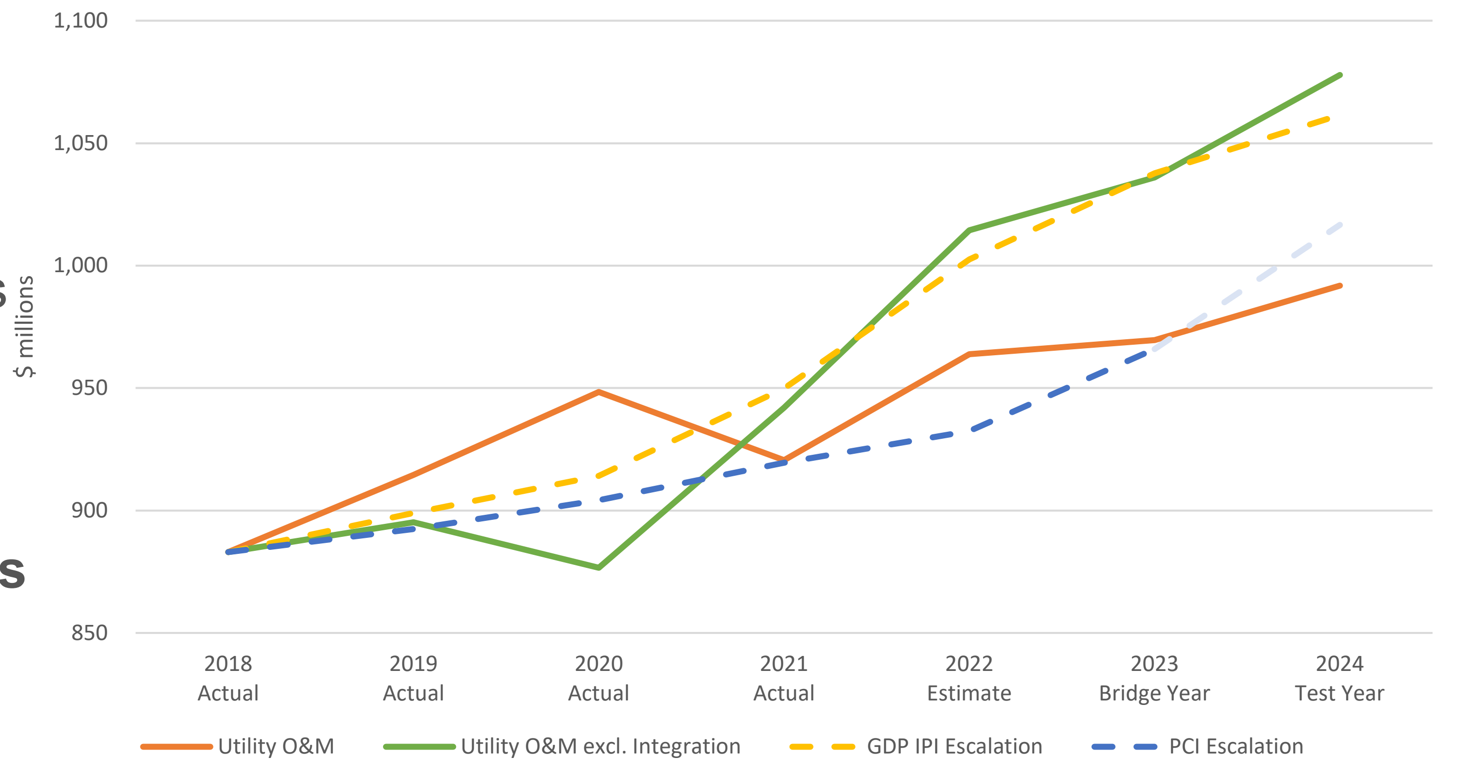


2024 earnings reflects return of amalgamation synergies offset by equity thickness and rate base growth

O&M Proposal – Synergies and Productivity

- Significant Synergies and productivity delivered in O&M through deferred rebasing term
  - $36M already delivered to customers through stretch factor
  - $121M Synergies and Productivity to be delivered by **alignment of organization structure** and **systems**
- Synergies and productivity have mitigated the impact of cost pressures above inflation

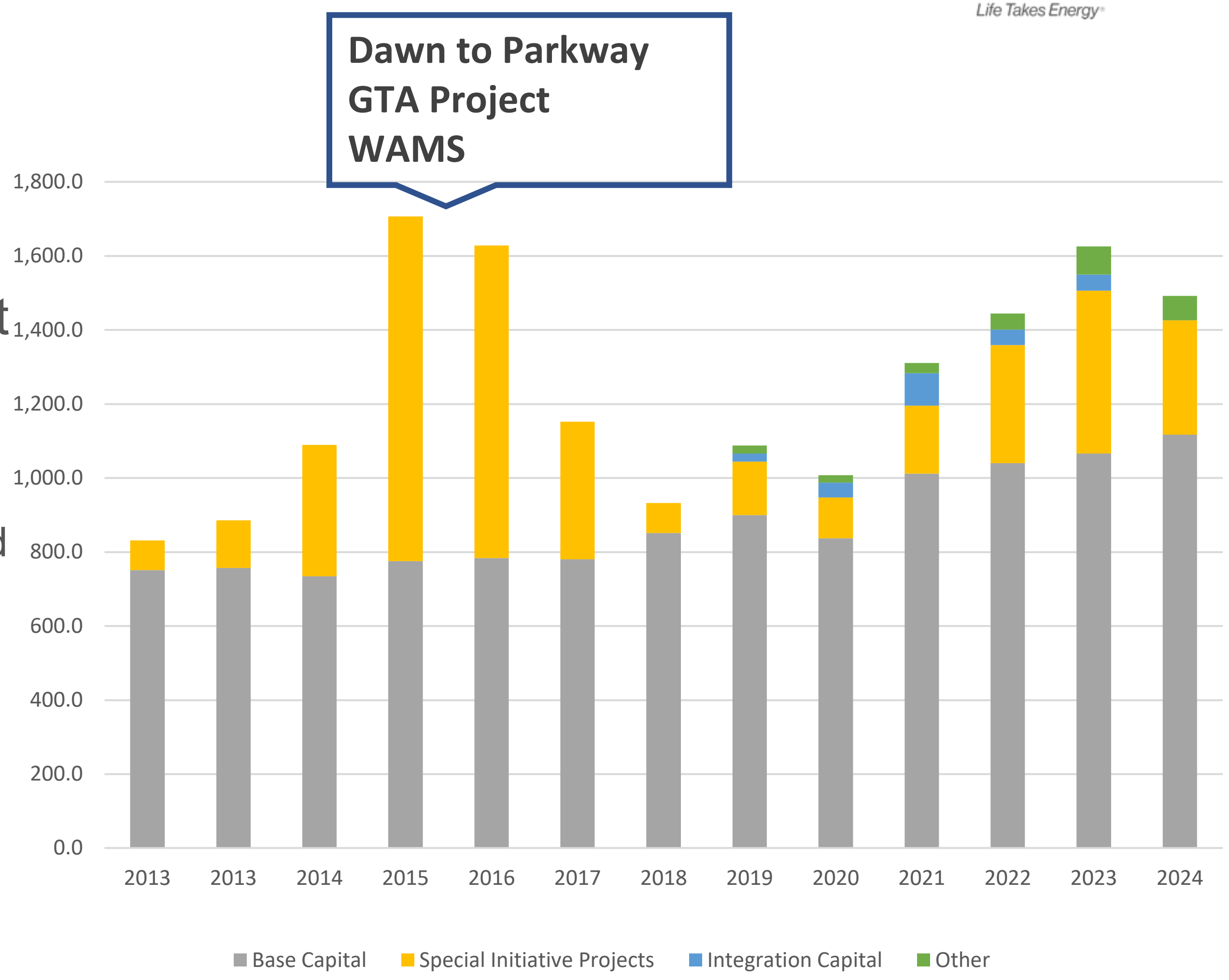


Ratepayers benefit as synergies and productivity have mitigated the impact of cost pressures above inflation

Notes:
OEB Price Cap Index (PCI) escalation reflects a two-year lag relative to actual inflation measured by GDP IPI measure

The Rate Base Proposal

- Annual base capital increases since 2020
  - Growth, integrity, COVID and inflationary cost pressures
- 2024 rates will include 2022 and 2023 forecast rate base additions
- Rate Base deficiency drivers include:
  - Net book value of cost overruns in GTA* project and WAMS* (2015-16)
  - Net book value of Integration capital
  - Shortfall in Rate Base recovery during deferred rebasing (10% stretch on base capital per OEB Policy)
- Rate impact mitigated by lower cost of capital than existing rates

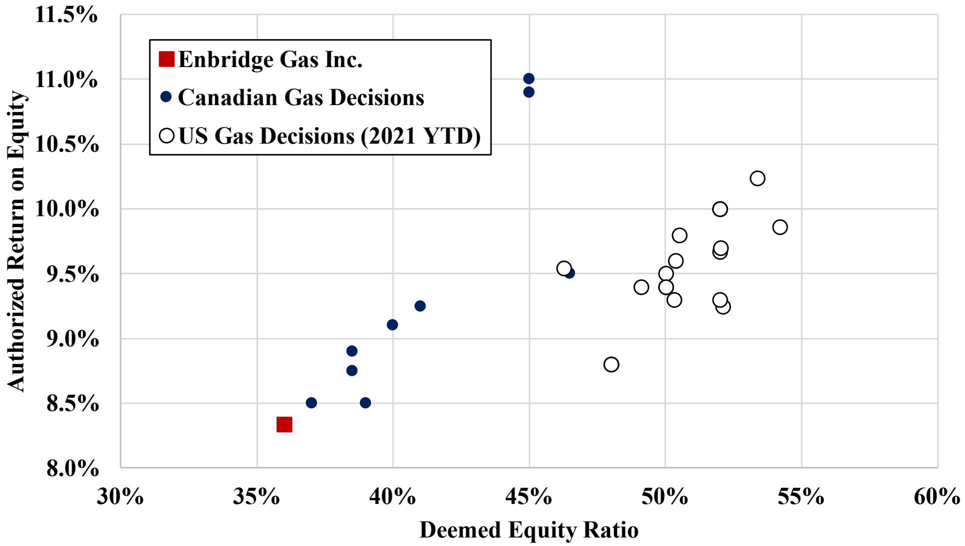


Rate Base additions since 2013 create pressure on 2024 rebased rates, partially mitigated by lower cost of capital

Notes:
GTA Pipeline project and the Work and Asset Management Projects delivered significant benefits through lower delivered natural gas costs, reliability and technology

The Equity Thickness Proposal

- The OEB test for changes in equity thickness is increase in business risk.
- Independent study shows material increase in business risk since 2013 and lowest equity ratio among comparables
- Study encompassed five primary aspects of the Company's risk profile
    1. Energy Transition risk – Significant increase
    2. Volumetric risk – Modest increase
    3. Financial risk – Modest increase
    4. Operational risk - Modest increase to Neutral
    5. Regulatory risk - Modest decline due to fixed rate proposal
- Recommended range of 40%-45%, with point estimate of 42%



- EGI proposal is equity thickness of 38% in 2024 and 1% annual increases to 42% in 2028 strictly for the purposes of smoothing customer rate impacts.

Recommending 5 year phase-in of equity thickness to manage customer rate impacts

The Depreciation Proposal

- EGI's practice is to conduct a Depreciation Study to support depreciation expense at Rebasing Application
  - Routine Methodology and Service Life assessment result in higher depreciation expense
    - "Equal Life" grouping method reduces inter-generational equity, supports Energy Transition
    - Amortization Accounting appropriate for units of property that are not practical to depreciate on an individual basis
    - Constant Dollar Net Salvage used for Site Restoration costs is more equitable for customers and is adjusted for return on capital and inflation
    - Date specific Economic Planning Horizon (EPH) was not proposed at this time, however, would be revisited if significant move to electrification is implemented through provincial legislation and policy
  - Harmonization proposal aligns useful lives of like assets to the shorter life used by the two legacy utilities
  - Depreciation Study will increase depreciation expense by ~$150M and the revenue deficiency by ~$200M

Depreciation asks are well supported by independent studies and/or regulatory precedents

Incentive Rate Mechanism Proposal (2025-28)

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- Rates will be set by using an Price Cap Formula calculated as (I - X) ± Y ± Z + ICM, where:
  - I = Weighted inflation factor (75:25 non labor inflation (GDP IPI to labor (average hourly earnings)
  - X = productivity factor and stretch factor (1.35% “adder” to inflation to reflect negative productivity)
  - Y = Costs not subject to Price Cap escalation (pass-through items such as gas costs, energy efficiency programs and specific costs afforded the pass through treatment)
  - Z = costs associated with unforeseen events outside of management control ($5.5M threshold)
  - ICM = Incremental Capital Module to seek funding for incremental capital projects that meet criteria of need, prudence and materiality and exceed the level supported by the formula
  - Earnings Sharing Mechanism, applicable if earnings exceed 150 basis points above allowed ROE, with 50/50 sharing between ratepayers and shareholders (same as current)

Independent consultant recommends rate increases exceeding inflation to reflect NA gas utility cost trends

1. To be finalized

Energy Transition

Divergent emissions targets create uncertainty

Feds focus on net zero

↓40%
Targeted reduction over 2005 levels by 2030[1]

↓40%
Federal GHG reduction left to achieve2030 target[1,2]

Prov. Gov focus on affordability

↓30%
Targeted reduction over 2005 levels by 2030[1]

↓~10%
ON GHG reduction left to achieve 2030 target[1,3]

Larger munis focus on net zero

70%
Have plans to meet net zero targets

2
Toronto & Ottawa plan aggressive move off gas by 2040

Energy Transition and Rebasing Implications

- Enbridge Gas will continue to deliver 2X electric energy and > 4X electric peak capacity over plan period
- However, climate policy creates divergent views on what constitutes sufficient funding to run business during plan period and invest long lived capital

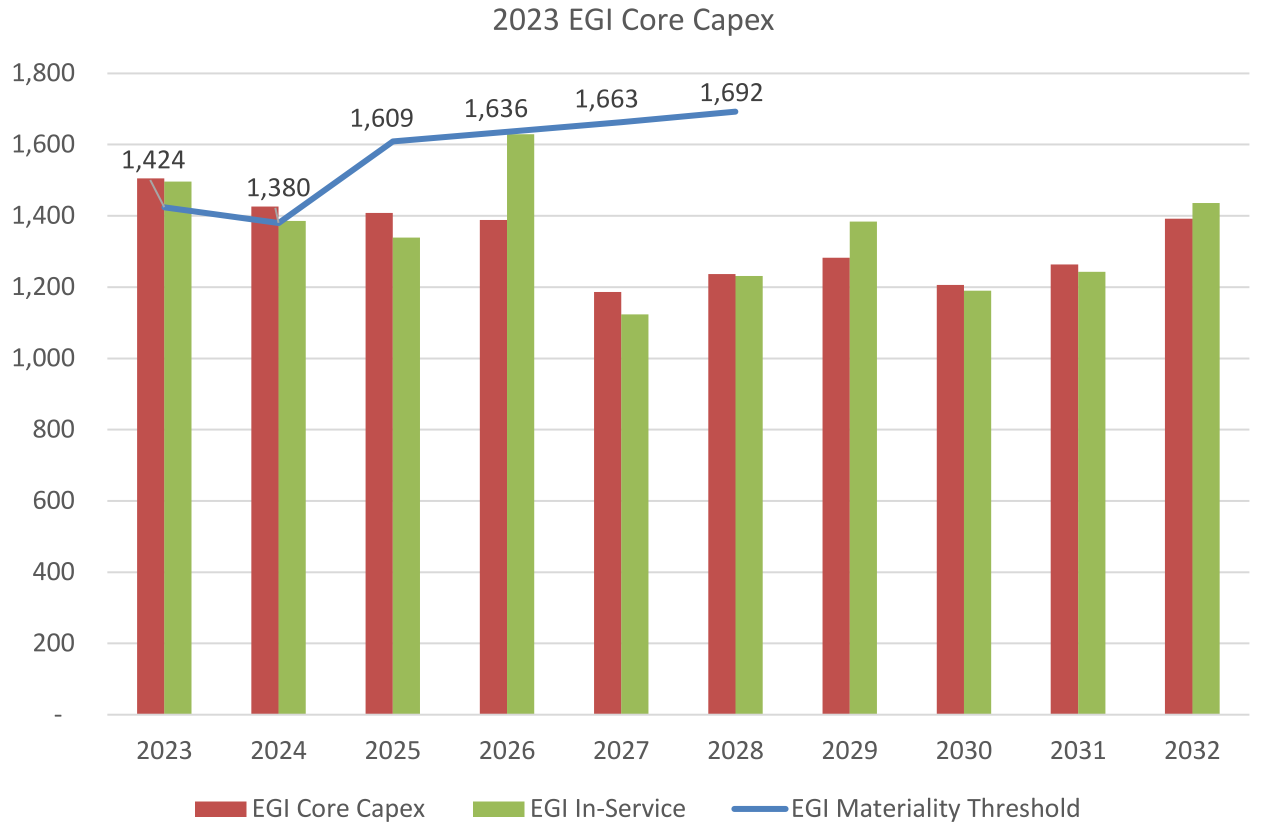
1. Absolute emissions reduction target
2. Federal GHG emissions have grown in other jurisdictions: therefore, full 40% reduction required
3. ~20% achieved via coal plant closures.

Demand Uncertainty due to Energy Transition

Demand Horizon	Risk Mitigant
Uncertainty in demand over plan period	Reflect declining customer additions and plan for lower increments in peak hour and peak day Eliminate revenue volatility by implementing fixed charge recovery of fixed costs (2025/26 implementation) and deferral account treatment for volume variances starting in 2024. Implement Integrated Resource Planning to optimize investments in gas carrying assets, demonstrate prudence (see slide 14)
Uncertainty in demand over life of assets	Commissioned third party study on net zero pathways to inform future policy direction. Diversified pathway including low carbon fuels is $200B and 27% less expensive than electrification pathway. Study presumes the displacement of natural gas with hydrogen over time, with larger volume flow from blended gas File depreciation expense estimates based on 2050 Economic Planning Horizon

The Asset Management and Integrated Resource Plan Proposal (IRP)

- Capex levels demonstrate base capital requirement over the longer term.
- IRP contemplates displacement of pipe with non pipe solutions
- Credible IRP implementation plan critical to recovery of capex in rates
- Strong justification for growth capex within the context of enhanced co-ordination with municipalities and electric LDCs/IESO.
- Strong justification for replacement capex with enhanced integrity approach for distribution pipes



Actively seek opportunities to optimize capex

Enabling Energy Transition through regulation

"Safe Bet" Initiatives	Proposal
Renewable Natural Gas (RNG)	Voluntary RNG backed by system supply, blend percentage rising annually with a 4% blend by 2028
Hydrogen Readiness	Expanding Markham pilot to 16,000 customers, system wide blending study and demonstrate path to increased system wide blending
Energy Transition Technology Fund	$25M rate rider over 5 years to enable low carbon technologies for RNG, hydrogen and end use technology

Modest rate increases to pursue "safe bet" energy transition initiatives

Harmonization proposals add complexity to case

OEB requires harmonization proposals	Impacts on Rates and timelines
Peak design criteria for gas supply procurement and distribution planning replacing legacy criteria	Rates Impact – Neutral When - 2024
Gas supply cost harmonized across province replacing geographically differentiated prices	Rates Impact – range of decreases and increases When - 2024
Depreciation expense methodology replacing legacy approaches	Rates Impact – Significant to some customer groups When - 2024
Customer Service and Rate Harmonization across province	Rates Impact – Significant to some customer groups When - implemented in 2025 and 2026 Capex for systems changes included in asset plan Ability to defer to meet Jan 1, 2024 timelines

Investigate options to contain scope or move to other process to manage Jan 1, 2024 timeline

Next Steps to Filing

- Complete legal reviews and premortem exercise
  - "Prospective hindsight" to inform strengths and weaknesses of plan
  - Facilitated by external counsel and Paula Conboy, ex OEB Commissioner
  - Focus on key revenue requirement components and potential for procedural delays due to complexity
- Oct 31- File revenue requirement and incentive framework evidence
- Nov 30 – File cost allocation and rate design evidence including rate harmonization proposal

Incorporate outcomes of legal review and premortem analysis into final evidence

Rebasing Application Timeline

Process Step	Estimated Timing
Notice	November, 2022
Interventions received	December, 2022
Procedural Order 1	January, 2023
Community meeting	January, 2023
Final issues list	early February, 2023
Interrogatories	mid-February to mid-March, 2023
Technical conference	late March to early April, 2023
OEB staff/Intervenor evidence	early April, 2023
IRs on intervenor evidence	late April, 2023
Settlement conference	early to mid-May, 2023
Oral Hearing	June, 2023
Argument (3 steps)	July to early August, 2023
Decision	October, 2023
Rate Order process	November, 2023
Implement new rates	January 1, 2024

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1

Question(s):

Please provide a copy of all third-party benchmarking analyses, studies, reports, and/or similar documents, undertaken for, or include Enbridge, since 2017, that are not already included in this application, regarding any aspect that directly or indirectly relates to a material aspect of Enbridge's business.

Response:

Enbridge Gas describes its continuous improvement philosophy and benchmarking in Section 6 of its Utility System Plan, provided at Exhibit 2, Tab 6, Schedule 1.

Enbridge Gas participates in annual benchmarking studies through its membership in the Canadian Gas Association (CGA) and American Gas Association (AGA). The AGA also addresses special topic areas, which have included: Contractor Oversight, Transmission Integrity, ROW Encroachment and Permitting, System Collection and Maintenance of As-Builts, QC and Training, DIMP, Emergency Response and Preparedness, Main and Service Construction, System Regulation and OPP, Carbon Emission Reduction, Leak Repair, Damage Prevention, Gas Control and Gas Compliance.

Both the CGA and AGA have confidentiality agreements in place which require signatories to request permission to distribute their work. CGA and AGA did not grant Enbridge Gas this permission and as such, Enbridge Gas cannot provide the reports.

Additionally, Enbridge Gas participated in customer satisfaction benchmarking studies: Mastio 2022 Transportation Customer Value/Loyalty Benchmarking Study and JD Power 2019 Gas Utility Residential Customer Satisfaction Study.

The Mastio Study is a customer satisfaction and loyalty benchmarking study covering North American pipelines (transportation market). Mastio did not give Enbridge Gas permission to share the study, however a press release for the 2022 study is available online[1]

The JD Power Study is focused on residential customer satisfaction with natural gas, electric and hybrid utilities in the United States, however EGD opted to participate. The results of this study do not include Union or Enbridge Gas, and relate only to 2018. The report was provided on a confidential basis.

Finally, Enbridge Gas subscribes to ESource, which is a subscription-based consulting, data and advisory service provided to North American utilities. The main topics it covers are: electric vehicles, AMI implementation, electrification, batteries, energy equity, customer experience, grid and asset optimization, demand response, and program design. Enbridge Gas was included in the following benchmarking studies:

- 2019 Website Benchmark Study
- 2021 Website Benchmark Study
- 2021 Digital Metrics Service Requests Study
- 2021 Digital Metrics Bill Pay Study
- 2022 Customer Experience Study
- 2021 Utility Social Media Study
- 2018 Utility Social Media Study (Union Gas)
- 2021 Account Management Assessment

ESource granted permission to list the benchmarking studies, but did not grant permission to share the reports.

[1] https://www.mastio.com/_files/ugd/43ede9_733cd1117d574e6fa5dbf06fc8e7a32c.pdf.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1

Question(s):

Please provide a copy of all budget guidance documents that were issued regarding the budgets that underlie the application.

Response:

Please see the Approach and Guidelines for GDS 2023 Financial Planning Process memo in Attachment 1 and the Enbridge Budget and 5+7 memo plus interest rate assumptions in Attachment 2.

At the time of distributing the Process memo, certain assumptions were not yet available. The following updates were made later in the process:

- FX Rates: set at 1.25 USD/CAD for 2023 to 2026 as per Attachment 2

- Long-term & Short-term Interest Rates: as per Attachment 2

    - Short Term: 2.9% for 2023 to 2024, 2.4% for 2025, and 2.1% for 2026
    - Long Term 10 Year: 3.1% for 2023, 2.9% for 2024, 2.8% for 2025, and 2.7% for 2026
    - Long Term 30 Year: 3.1% for 2023, 3.0% for 2024, 2.9% for 2025, and 2.9% for 2026

- PCI: PCI was updated to 3.6% for 2023 based on revision of 2021 quarterly inflation index by Statistics Canada in June 2022. For 2025 and 2026, the PCI assumption was updated to 3.04% based on an estimated productivity factor of -1.04% at the time of budget finalization.

- Merit: was updated to 4% for 2023, 5% for 2024, and 3% for 2025 to 2026.

Colin Healey
Director FP&A

Catherine Ho
Manager FP&A

Date: March 31st 2022

Re: **Approach and Guidelines for GDS 2023 Financial Planning Process**

The purpose of this document is to provide an awareness of the guidelines and timelines for the preparation of the GDS Budget and Long-Range Plan (LRP) for years 2023-2026. The preliminary budget & LRP will also form the basis of the rebasing application for 2024, while 2025 and 2026 will form the last two years of the LRP.

The 2023 Financial Planning Process timeline is as follows:

Budget Deliverable	Due Date	Accountability
EGI Capital Budget and LRP	23-May-22	Finance, Asset Management
EGI O&M Budget and LRP	29-Apr-22	Finance, Business
Other GD/Affiliates	Mid-June	Finance, Business
EGI Revenue Budget and LRP	22-Jun-22	Finance, Business
EGI Cost of Gas Budget and LRP	30-Jun-22	Finance, Business
Budget & LRP Approval	Late July	Finance, Michele Harradence
Budget & LRP Presented to Corporate	6-Sep-22	Finance
Budget and LRP submission	16-Sep-22	Finance

General 2023 Budget Planning Approach

- The EGI Budget will be based on a **price cap** rate setting mechanism for year 2023; 2024 will be based on **cost of service** as part of rebasing; 2025 and 2026 will be based on a price cap rate setting mechanism.

- EGI's 2022 2+10 Forecast will form the basis of evidence for the year 2022 in the rebasing application, and it should be used in calculating ending balances and rolling forward schedules as required for 2023. The preliminary 2023 Budget and 2024 LRP will form the basis of the 2023 and 2024 years of the Rebasing filing, respectively.

- EGI's 10-year Asset Management Plan (AMP) will be used to derive the capital expenditure outlook for each year of the Budget and LRP, including a list of projects and spend that meet the Incremental Capital Module (ICM) criteria for years 2023, 2025 and 2026.

High level guidelines for the development of the Budget and LRP are provided below:

Revenue Guidelines	• The General Service (GS) Budget will be based on forecasted volumes and rates. Volumes are determined by forecasted customer count and average use. Forecasted customer count is based on forecasted housing starts, conversions, community expansion and attrition assumptions. Forecasted average use is based on historical trend analysis that includes a normal weather assumption, efficiency gains (including Demand Side Management (DSM)), and prices. • The Contract Market (CM) budget is based on a forecast of fixed Contract Demand (CD) charges as well as variable charges based on forecasted consumption. The forecasts of both of these components are developed primarily through a bottom-up approach, based on direct engagement with existing customers. The forecast will also include volumes and revenues associated with capital projects, in alignment with the AMP. • The S&T budget is prepared in two phases – the volume forecast and the revenue forecast. The volume forecast is based on contracted volumes from existing customers and any additional volumes from potential future growth and expansion projects, in alignment with the AMP. Transportation revenue is determined by applying rates provided by Rates to fixed contracted demand volumes and a variable charge based on forecasted consumption. Storage revenue is a combination of revenue from existing contracts and a forecasted competitive market rate applied to available storage capacity. • Regulatory items such as deferral accounts that impact revenue (APCDA, TVDA, ICM, etc) are layered on as required. • 2023 Filed Rates will be based on PCI escalation and will be applied to the volumetric budget to generate revenues for 2023. • Revenues for 2024 will be based on revenue requirement determined based on a Cost of Service application. Revenues for 2025 and 2026 will be escalated from 2024, based on a forecast of PCI. • Volume budgets will be reviewed and approved by Directors and VPs in April, and Revenue budgets will be reviewed and approved by Directors and respective VPs throughout May and June before being consolidated into EGI's Budget.

Capital Guidelines	• Finance will provide the ICM Threshold for years 2023, 2025 and 2026. • The EGI AMP will be used to determine core capital spend and proposed ICM project spend based on prioritization and optimization. The budget will be optimized by rate zone for 2023. Upon rebasing, it will be assumed that EGI will operate under one rate zone. • The Budget and LRP will include both Core and Non-Core Projects.
O&M Guidelines	• The 2023 Budget and 2024 LRP will be developed following a grassroots approach to support a fully defendable cost of service for the Rebasing application. Inflation assumptions are to be applied to current cost estimates, unless there are known and identifiable adjustments (increases/decreases) to cost estimates that are required to reflect current market conditions, for example, where different inflation assumptions should be applied. • All one time program costs (increases/decreases) should be reflected in your budget and LRP submission. • The O&M budget process commenced on February 7th with the Overhead Capitalization Study and will wrap up by April 29th to fulfill regulatory timelines. • The Workforce Budget (WFB) process will be managed separately in light of the compressed timelines. O&M analysts started working with Directors and VPs in early March and will complete entry and consolidation in the WFB tool on their behalf. VP approvals need to be completed by April 22nd. • The WFB is based on FTEs as of February 28th inclusive of any approved vacant positions. The goal is to keep FTEs flat. Any adjustments will be subject to senior leadership approval. • The Cost to Achieve (CTA) program ends as of December 31, 2023. Any new CTA spend in 2023 will be subject to business case approval, where project savings are required to offset project costs in 2023. • A budget package with additional information, instructions and templates was sent the week of March 7th. O&M analysts will be working with their business clients in advance of this date.

Key Assumptions for 2023 Budget and LRP years

2023 Budget and LRP Input	Assumptions
PCI*	3.8% for 2023, N/A for 2024, 2% for 2025-2026
Inflation (CPI)	2.4% for 2023, 2.2% for 2024, and 2% for 2025-2026
FX Rates	TBD

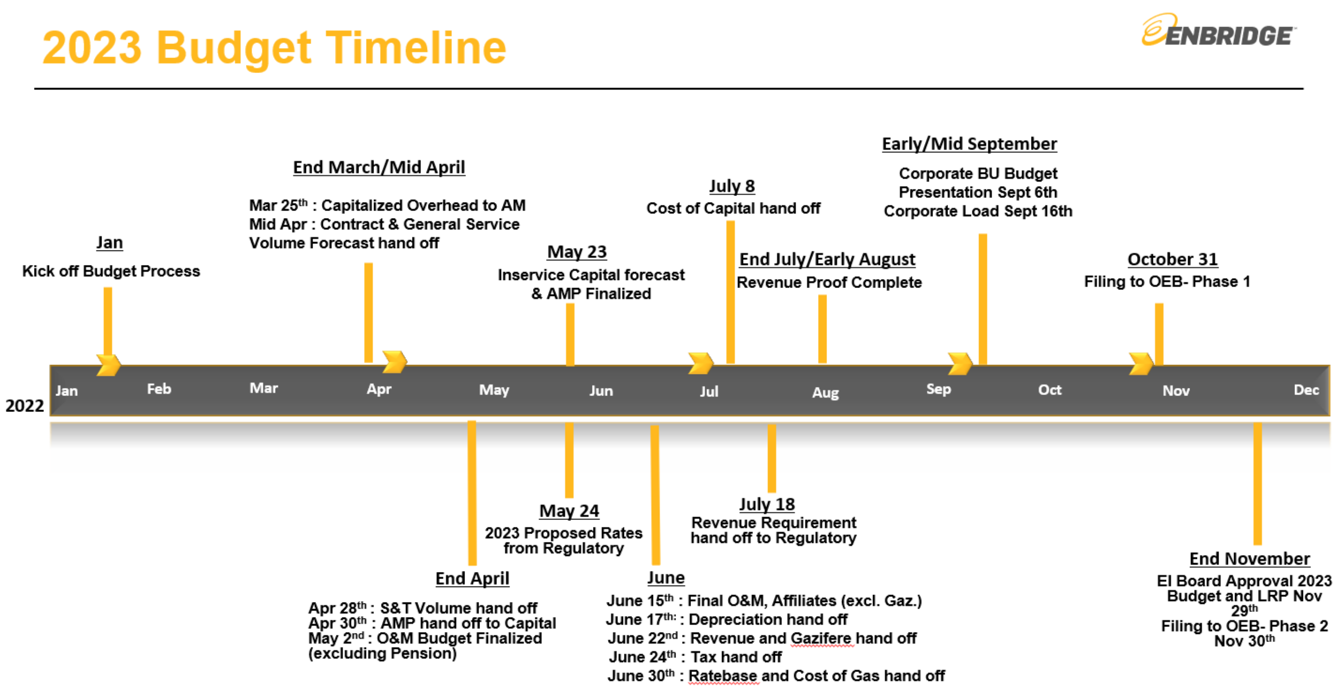
Long term & Short-term Interest Rates	TBD
Salary Escalation – non-Union employees	3%
Salary Escalation – Union employees	Per Collective Agreement

**Stats Can may be providing update June 1st with revised inflation benchmark – update may be required

Budget Contacts

Subject Matter	Contact
Capital	Danielle Dreveny
O&M – Utility, Central Functions	Margarita Suarez
Workforce Budget (WFB) Support	Amna Dhaliwal, Kenneth Cheung
Contract Market, Other, S&T and Transactional Services Revenue, Gas Costs	Rachel Goodreau
General Service Revenue	Gilmer Bashualdo-Hilario
APCDA, TVDA & Ratebase	Jason Vinagre
Tax	Evgenia Vangelova
Investment Review	Stuart Murray
Affiliates	Theresa Nappi
General Planning Guidelines	Catherine Ho Sam Bradley

Appendix #1: 2023 Budget Timelines



From: Thomas Pang
To: Robert Yaremko; Pamela Young; Brad Kopas; Alan McCoy; Brenda Rijavec; Nazmul Haque; Zeyd Khan; Carlos Vasquez; Sharmin Maredia; Odalis Miranda; Cara Griffeth; Greg Tapuska; Colin Healey; Catherine Ho; Monica Woodward; Jason Shem; Courtney Adcox; Zoe Smibert; Ryan Johnson; Candace Tracey; Brea Meadows; Simran Assie; Yael Costilla; Dave Marks; Ricki Boudreau; Jenn Pound; Kimberley Ronan; Rajiv Krishnan; Christina Grierson; Bethany Shermack
Cc: Pat Murray; Melissa LaForge; Steve Neyland; Tanya Ferguson; Eanna Smyth; Nafeesa Kassam; Andrew Wedel; Calgary B & F Team; Michael Broeders; Marko Laschuk; Grant Bateman
Subject: INFORM: BUDGET & 5+7
Date: Friday, May 20, 2022 9:04:01 PM

Hi all,

Below and attached are the key dates and information for the 5+7 and the Budget.

Summary

- Please see attached assumptions for the Forecast / Budget and LRP. Updated assumptions for Budget/LRP will be circulated for consideration in August.
- EPBCS is open for inputs for both Forecast and Budget/LRP
- USD/CAD FX Rate set at **1.25** for Forecast and Budget/LRP
- Presentation decks: Please continue to customize as necessary but include, at a minimum, the information in the attached Templates.

5+7 Forecast:

- Presentations are booked for the week of **June 14**
- EPBCS Load Deadline **June 16**
- Allocations True-Up for forecast months **June 16**
- BU SEGTYD Signoff **June 17**
- BU STIP Scorecards due to Corporate FP&A **June 23**
- Interest Signoff **June 24**
- Tax Signoff **June 30**

Budget/LRP:

- The BU review meetings (including the CFO and ELT members) are scheduled for the week of **September 6th**
- Hyperion load deadline **September 16**
- Risked capital listing **September 16**
  - Updated risked capital listing (for projects not included in the plan) including: Project Name, Description (if available), Organic vs Acquisition, Capex ($) by year of the plan, Estimated ISD Target, Risk Weighting (%), EBITDA by year of the plan or EBITDA Multiplier (if available), any other relevant information.
- Sign off on BU EBITDA/DCF **September 19** (including Equity Earnings/Dividends, AFUDC, Core Maintenance, Other DCF Adjustments, Depreciation, NCI (if relevant))
- Treasury sign off **September 27**

Tax sign off **October 3**
- ROCE sign off **October 14 (Tentative)**

We are aiming to distribute Budget/LRP Targets in Mid-June.

System Updates:
The LRP process for Non-O&A accounts (Revenue, Equity Earnings, COS etc) has been changed in EPBCS in order to provide more control over accounts that aren't typically escalated.

Legacy Process: Budget data is entered into the budget year and pushed into LRP periods and;
- Can then be escalated by x% in the LRP years
- Can further be adjusted using 'LRP input'

Revised Process:
- Remove escalation functionality for non O&A: Revenue, Cost of Sales, Equity Income etc.
    - This means the LRP input form will be restricted to O&A accounts only
    - Existing Plan forms for Revenue, Cost of Sales, Other Income/Expense etc that used to only have budget year data, will now have LRP years and can be entered into directly (Dec only)

Please let me know if you have any questions or concerns.

Thanks,
Thomas Pang

Interest Rate Forecast Methodology: Average of Bank Economic Forecasts

LRP Interest Rate Price Deck Update

May LRP Interest Rate Price Deck		Spot (May 20)	2022	2023	2024	2025	2026
Interest Rates - CAD							
Short Term	**3 Month CDOR**	**2.0%**	**2.3%**	**2.9%**	**2.9%**	**2.4%**	**2.1%**
	1 Month CDOR	1.6%	2.1%	2.7%	2.7%	2.4%	1.9%
	3 Month T-Bills	1.4%	1.9%	2.6%	2.4%	2.2%	2.0%
	CAD Prime	3.2%	4.1%	4.9%	4.8%	4.4%	4.2%
Long Term	**5 Year GOC Bond**	**2.7%**	**2.8%**	**3.0%**	**2.8%**	**2.7%**	**2.6%**
	10 Year GOC Bond	**2.8%**	**3.0%**	**3.1%**	**2.9%**	**2.8%**	**2.7%**
	30 Year GOC Bond	**2.8%**	**3.0%**	**3.1%**	**3.0%**	**2.9%**	**2.9%**
Interest Rates - USD							
Short Term	**3 Month LIBOR**	**1.5%**	**2.0%**	**2.8%**	**3.0%**	**2.7%**	**2.8%**
	Overnight SOFR	0.8%	1.8%	2.8%	2.9%	2.6%	2.3%
	1 Month LIBOR	1.0%	1.7%	2.3%	2.7%	2.5%	2.4%
	3 Month T-Bills	1.0%	1.9%	2.7%	2.6%	2.4%	2.2%
	US Prime	4.0%	5.0%	5.9%	5.9%	5.6%	5.4%
Long Term	**5 Year UST Bond**	**2.8%**	**3.0%**	**3.1%**	**2.9%**	**2.7%**	**2.6%**
	10 Year UST Bond	**2.8%**	**3.1%**	**3.1%**	**3.0%**	**2.8%**	**2.8%**
	30 Year UST Bond	**3.0%**	**3.1%**	**3.2%**	**3.1%**	**2.9%**	**3.0%**

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1

Question(s):

For each year since 2018, please provide a copy of any corporate scorecards, and any other similar annual documents, that Enbridge or Enbridge Inc. uses to set internal targets and track the performance of Enbridge's business.

Response:

Enbridge Gas's OEB scorecard was established in the MAADs proceeding[1]. The OEB scorecard results for 2017 to 2021 are provided at Exhibit 1, Tab 7, Schedule 1, Attachment 1, page 1.

Internal scorecards outline goals and measure performance during the year. Targets are set using a methodology that considers past performance and stretch goals for continuous improvement.

The internal Gas Distribution and Storage (GDS) business unit[2] scorecards for the years 2019 through 2022 are provided at Attachment 1. Scorecards are used to measure internal performance and achievement of scorecard objectives and are directly linked to the Short-term Incentive Plan (STIP). Of note, some results have been impacted by the alignment of systems and processes through amalgamation.

[1] EB-2017-0306/EB-2017-0307
[2] Enbridge Gas is part of the Gas Distribution and Storage business unit

Enbridge Gas Inc.

2019 Scorecard

▲ Above target (> 1.25 multiplier)
○ On target (1.00 - 1.25 multiplier)
▼ Below target (< 1.00 multiplier)

#	Performance Measure Year-End Update	Weight	Year-End Target Doesn't Meet	 Meets	 Exceeds	Result	Scope
#	SAFETY	16.5%	0x	1x	2x		
1	Total Recordable Injury Frequency - Employee Recordable injuries per 200,000 hours worked	4%	0.73	0.66	0.55	▼	Enterprise Wide Shared Target and Result
2	Total Recordable Injury Frequency - Contractor Recordable injuries per 200,000 hours worked	4%	0.90	0.75	0.55	▲	Enterprise Wide Shared Target and Result
3	Motor Vehicle Incident Frequency (MVIF) (# of vehicle incidents x 1,000,000 kms) / employee kms driven	3.5%	1.45	1.19	0.95	▼	Enterprise Wide Shared Target and Result
4	Safety Leadership in Action	5%	80%	90%	100%	▲	Enterprise Wide Shared Target and GDS Result
	OPERATIONS & INTEGRITY	13.5%	0x	1x	2x		
5	Damages First, second and third party line breaks per 1,000 locate requests	5%	2.16	1.97	1.94	○	EGI Shared Target and Result
6	Incident Investigations (Composite) Includes Incident Investigation Completed on time and Management Committee Review	4%	80%	90%	100%	▲	Enterprise Wide Shared Target and GDS Result
7	Compression Reliability % reliable for transmission compression	4.5%	99.24%	99.8%	1x target and reduce $291K cost of repairs	▲	EGI shared Target and Result
	CYBER SECURITY	5%	0x	1x	2x		
8	Phishing Hardiness (simulated tests) The % of people who clicked (negative contributor) subtracted from % of people who reported the phishing email (positive contributor)	2.5%	30%	50%	77%	▲	Enterprise Wide Shared Target and Result
9	Real Phishing Attacks Prevented by Users The % of known e-mail phishing attacks that did not require intervention due to employee vigilance	2.5%	98.5%	99%	99.5%	▼	Enterprise Wide Shared Target and Result
	FINANCIAL	40%	0x	1x	2x		
10	Distributable Cash Flow (DCF)	40%	1,647	1,707	1,767	▲	UPO and GDS Combined Target and Result
	WORKFORCE	5%	0x	1x	2x		
11	Decision Effectiveness Average overall improvement in measures of Quality, Yield, Speed & Effort	5%	73%	74.5%	76%	▲	Enterprise Wide Shared Target and Result
	GROWTH	20%	0x	1x	2x		
12	Quantity of growth capital commercially secured (Million) Capital committed to organic growth projects or acquisitions	20%	200	300	400	▲	EGI Shared Target and Result
	TOTAL SCORECARD WEIGHTING	100%				1.62	

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GDS 2020 Scorecard

▲ Above target (> 1.25 multiplier)
○ On target (1.00 - 1.25 multiplier)
▼ Below target (< 1.00 multiplier)

#	Performance Measure Year-End	Weight	Year-End Target Doesn't Meet	Meets	Exceeds	Result Score		Scope
#	**SAFETY**	**15%**	**0x**	**1x**	**2x**	**200%**		
1	**People Not Getting Hurt** *Recordable incidents per 200,000 employee and contractor hours worked*	10%	1.05	0.95	0.90	200%	▲	GDS Targets and Result
2	**EHS Leadership in Action (EHSLiA)** *People leader participation (% leadership participation) and quality leadership in action activities (# per year)*	5%	90%	95%	100%	200%	▲	GDS Targets and Result
	OPERATIONS & INTEGRITY	**20%**	**0x**	**1x**	**2x**	**182%**		
3	**Total Damages Per 1000 locates** *First, second and third party line breaks per 1,000 locate requests*	5%	2.71	2.46	2.21	189%	▲	GDS Targets and Result
4	**Emergency Response (<60 Minutes)**	5%	94%	96%	98%	140%	▲	GDS Targets and Result
5	**Integrity Plan Completion**	5%	90%	95%	100%+ immediate digs mitigated (60 days)	200%	▲	GDS Targets and Result
6	**Regulatory Orders Closed in 30 days** *Root Cause Preventative Action Plan Completed*	5%	60%	70%	80%	200%	▲	GDS Targets and Result
	CYBER SECURITY	**5%**	**0x**	**1x**	**2x**	**178%**		
7	**Phishing Hardiness (Simulated Tests)** *% of positive contributors (those who reported) less % the negative contributors (those who clicked) = Hardiness Factor*	5%	35	55	75	178%	▲	Enterprise Wide Shared Targets and Result
	FINANCIAL	**40%**	**0x**	**1x**	**2x**	**200%**		
8	**Distributable Cash Flow (DCF)**	30%	1,168	1,204	1,240	200%	▲	GDS Targets and Result
9	**GDS Corporate ROE** *Includes Gazifère and Unregulated Business*	10%	9.93%	10.21%	10.49%	200%	▲	GDS Targets and Result
	GROWTH	**20%**	**0x**	**1x**	**2x**	**100%**		
10	**Quantity of growth capital commercially secured (Million)** *Capital committed to organic growth projects or acquisitions*	20%	300	400	500	100%	○	GDS Targets and Result
TOTAL SCORECARD WEIGHTING		**100%**					**1.75**	

▲ Above target (> 1.25 multiplier)
○ On target (1.00 - 1.25 multiplier)
▼ Below target (< 1.00 multiplier)

GDS 2021 year-end results

Key performance indicator	Weight	Year-end target: Doesn't meet	Year-end target: Meets	Year-end target: Exceeds	Year-end
Ensure safe, reliable operations	**40%**	**0x**	**1x**	**2x**	
People not getting hurt Total recordable injury frequency (TRIF) per 200,000 employee and contractor hours worked	15%	1.02	0.88	0.83	▲
Total damages per 1000 locates First, second and third party line breaks per 1,000 locate requests	10%	2.70	2.20	1.96	▲
Integrity inspections and assessments Complete percent of all planned pipeline, storage downhole and facility integrity inspections, assessments and repairs	10%	• No transmission pipeline ruptures and complete 90% of the plan	• Complete 95% of the plan	• Complete 100% of the plan and 10 additional units of work	▲
Cybersecurity: predictive susceptibility to a real phishing attack Percent clicked on compliance phishing test	5%	7%	5%	3%	○
Maintain financial strength and flexibility	**40%**				
Distributable Cash Flow (millions)	20%	$1,438	1,483	1,527	▲
EBITDA (millions)	20%	$1,758	1,812	1,867	▲
Progress toward our ESG goals	**10%**				
D&I	5%				
Composite	5%	0%	100%	200%	○
Emissions	5%				
GHG emissions reduction	5%	0%	100%	200%	○
Execute and extend growth	**10%**				
EBITDA generated by growth capital (millions) Includes organic growth projects and M&A	10%	$17	$25	$33	▲
Total	100%			2021 multiplier 1.70x	▲

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GDS 2022 scorecard

		Year-end target		
Key performance indicator	**Weight**	**Doesn't meet**	**Meets**	**Exceeds**
Ensure safe, reliable operations	**35%**	**0x**	**1x**	**2x**
People not getting hurt Total recordable injury frequency (TRIF) per 200,000 employee and contractor hours worked	15%	1.00	0.76	0.68
Environmental incident frequency (EIF) Number of environmental incidents (non-compliances) per 200,000 employee and contractor exposure hours	5%	0.26	0.18	0.15
Pipeline system safety (PSS) Leak and release frequency (LRF) defined as: (Tier 1 Count x 10 + Tier 2 Count) x 1,000 kms/kms of pipelines	5%	0.21	0.10	0.08
Total damages per 1,000 locates First, second and third party line breaks per 1,000 locate requests	5%	2.28	2.07	1.86
Cybersecurity: predictive susceptibility to a real phishing attack Percent clicked on compliance phishing test	5%	6.9%	4.9%	2.9%
Maintain financial strength and flexibility	**35%**			
Adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA)	35%	1,784	1,839	1,894
Progress toward our ESG goals	**10%**			
D&I	5%			
Composite Net increase on overall diverse representation as a percentage of our workforce	3%	1.2%	1.5%	2.5%
Composite Employee/leader training completion percentage of completion of Indigenous awareness training	2%	90%	95%	100%
Emissions	5%			
GHG emissions reduction	5%	-8%	-4%	2%
Execute and extend growth	**20%**			
EBITDA generated by growth capital (millions) Includes organic growth projects and M&A	20%	$17	$30	$58
Total	100%			

ENBRIDGE®
Life Takes Energy®

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1

Question(s):

Please provide summaries of all internal audit reports conducted since 2013, related to any aspect that directly or indirectly relates to Enbridge's business, their findings, recommendations, and the status of any actions that have or are to be taken.

Response:

Please see Attachment 1 for summaries of internal audits relating to Enbridge Gas since 2019. Certain information has been redacted for security reasons and a confidential version will be filed separately with the OEB. Compiling information on internal audits for EGD and Union prior to 2019 would require a considerable amount of time due to changes in tracking systems and would also be of limited value as the findings relate to the predecessor organizations.

Engagement Name	Finding	Management Action Plan	Finding Status
Utilities - Purchase Gas Variance Account Assess the design of the legacy utilities' accounting policies, procedures, controls and processes associated with the PGVA and related commodity costs, including clearance of the account.	Widespread use of spreadsheets and manual input files which are prone to input error, lack protection and are not stored centrally	1. Access restrictions and version control for key spreadsheets prepared for gast cost, PGVA and QRAM by Cost of Gas team 2. Access Database for interim solution to reduce manual inputs into legacy EGD spreadsheets prepared by Cost of Gas team 3. Cost of Gas Replacement Project to be implemented to reduce reliance on manually-prepared data 4. Protections for key inputs and calculation cells as well as central storage of key files for QRAM by Regulatory	Closed
	Accountabilities within the Cost of Gas team are in transition	1. Monthly mock QRAM process to be implemented 2. Process documentation will be completed for QRAM and PGVA reconciliation processes	Closed
	Lack of documented operating procedures within Cost of Gas processes	Detailed operating procedures will be documented for key legacy EGD Cost of Gas tasks	Closed
SCADA Field Device Audit Assess the information technology controls related to management of SCADA field devices to determine if key controls exist and are effective, and that policies, processes, and procedures are in place to help ensure the security and availability of this class of assets.	GDS - An untrusted telephone network is directly connected to Remote Terminal Unit (RTU) modems without adequate protection.	Dial-up connections will be phased out and disconnected from all affected RTU Modem Ports at communication centers by January 24, 2020.	Closed
	GDS – Test procedures and results associated with configuration changes need to be formally documented.	Engineering will develop EGI standard for testing and recording of RTU changes	Closed
	GDS - Firewalls are not deployed where cellular modem has a direct serial connection to a RTU and the built-in cellular modem firewall is not enabled.	Stations with the 3330 RTU will be phased out and upgraded to Control Wave Mircro RTU architecture. The upgrade plan to be developed by Engineering and Telemetry team.	Closed
	STO - Multi factor authentication should be required for all connections initiated between the business and the control network.	Multi factor authentication solution will be implemented.	Closed
	STO – Passive vulnerability scanning capability should be available to monitor the OT control network environment.	ICS Segregation Program: Detection and Monitoring Phase 2 Track 1- Deployment of Silent Defense Sensors to 2020 Important site list (target of 150 sites), including the 140 that were deployed in 2019. Vulnerability Management – Phase 2 Phase II will extend the scope of the vulnerability management and patch management program to the OT environment. Build OT asset inventory, expand existing patching workflow to applicable assets in the OT environment, continue to support implementation of the IT environment patching process.	Closed
	[redacted]	[redacted]	[redacted]
	STO – Annual RTU configuration back up was not performed for 2019.	New work orders (site documentation) were created and rolled out to capture the requirements for documentation and backups. The SAP system was reviewed to ensure the work orders were created for all sites at Parkway for 2020, that they were consistent and called out the need to perform program backups. Complete review of the process as part of 2020 maintenance planning.	Closed

Engagement Name	Finding	Management Action Plan	Finding Status
SCADA Field Device Audit Assess the information technology controls related to management of SCADA field devices to determine if key controls exist and are effective, and that policies, processes, and procedures are in place to help ensure the security and availability of this class of assets.	STO - Test procedures and results associated with configuration changes need to be formally documented.	Currently MOC process development is underway including the updates to Form #8827 to document the information being changed for historical reference, approvals, reviewers as well as completion of bench test. Implementation of this MOC to be completed by year end. New MAP from Umair Khan (Sr Engineer Electrical Controls): 2 procedures are scheduled to be published - Engineering Approvals for Electrical and Control Assets (May 2021) and RTU program testing and recording procedure (Q3, 2022). The reason for the long cycle is that the engineering procedures are refreshed and approved on an established schedule. IA has updated the implementation date to Q3 2022.	Closed
Physical Location - GDS STO Assess the execution, awareness and existence of Life Saving Rules (LSR's) in the Gas Distribution and Storage (GDS) Storage and Transmission Operations (STO) Region that support safe and reliable operations.	Procedures for completion and review of hazard management activities and required documentation is lacking for Legacy Union Gas sites.	Response to this audit finding will be built into the safety program integration work. The legacy company site specific hazard assessment processes will be harmonized, and the new process will include an assurance component to monitor adherence to the process. The updated procedure will be rolled out to the Region through typical Management of Change process, and targeted training will be provided to Operations team members as required.	Closed - Management Accepted the Risk
	Lock-out-tag-out (LOTO) locks are being used for non-LOTO activities resulting in confusion of the locks purpose.	As part of integration activities lead by the Health and Safety team and supported in part by STO, a revised procedure outlining the use of operational locks will be implemented. The procedure will be communicated to the Region through the normal Management of Change process. To mitigate any short-term risk of confusion, the interim plan will be to clearly identify the operational locks currently used in the process and document the local process with a copy kept in the control room until the new procedures are finalized and implemented	Closed
S&R – Underground Storage Integrity Management Assess alignment with Enbridge's current operational processes and procedures applicable to the Underground Storage Integrity Program (Program). The Program considers the Management System Framework (MSF), and applicable Canadian and U.S. Underground Storage (UGS) Regulations, Codes and Standards including State and Provincial; Review and assess the maturity of the Program as it relates to operational risk management; Review and assess progress made in implementing management action plans from the prior Operational Risk Management Verifications	Criteria and training for operations have not been established for UGS activities.	Leverage the competency matrix developed for Distribution Integrity Management Program to develop the competency framework for SDIMP which includes a process for tracking progress. (Note: will leverage the Technical Competency Learning Path within Technical Training)	Closed
S&R - GDS Pipeline Integrity Management Assess alignment with Enbridge's current operational processes and procedures applicable to the Gas Distribution & Storage (GDS) Integrity Management Program (Program). The Program considers the Management System Framework (MSF) and applicable Canadian or Provincial Regulations, Codes and Standards	Hazard & Risk Register does not address all hazards and risks	Tranmission Integrity Management Program (TIMP) - Re-evaluate geotechnical hazards and associated risk and where appropriate, incorporate into hazard and risk register Distribution Integrity Management Program (DIMP) - Update the hazard register to ensure all hazards associated with water and bridge crossings are adequately identified.	Closed
	Collection and reporting of "leading indicators" needs improvement to support early indications of a potential issue	Identify appropriate leading indicators	Closed
	Assessments of life expectancy or time to failure has not been established	Work with other Enbridge Business Units to re-evaluate Engineering Assessments (EA) and Fitness for Service (FfS) methodology	Closed

Engagement Name	Finding	Management Action Plan	Finding Status
S&R - GDS Pipeline Integrity Management Assess alignment with Enbridge's current operational processes and procedures applicable to the Gas Distribution & Storage (GDS) Integrity Management Program (Program). The Program considers the Management System Framework (MSF) and applicable Canadian or Provincial Regulations, Codes and Standards	The process for technically qualifying contractors is not fully developed	TIMP - Work with Supply Chain to ensure their process for technically qualifying contractors adequately reflects the criteria DIMP - Assess if any improvements need to be made	Closed
	Over-reliance on contractor inspections and results	Develop processes to conduct vendor quality checks for In-line inspections (ILI) and Non-Destructive Examination vendors.	Closed
	The program does not account for a review of effectiveness of integrity controls	Develop Safety & Reliability (S&R) targets and KPI	Closed
	Assessments of non-inspected pipelines and mains are not addressed in risk model	Expand risk model to include non-piggable pipelines.	Closed
	There is no documented process for deferral of integrity activity	Include in the new Condition Monitoring Standard	Closed
	Subject Matter Expertise (SME) and programmatic oversight for pipeline threat needs improvement	Document the SME approach	Closed
	Key integrity position competencies are not identified	Leverage the DIMP competency matrix	Closed
	Inspection redundancies are not established for high-risk asset classes	Review and document the level of redundancies	Closed
Gas Purchasing Assess whether gas purchase controls and related processes allow for:i. Reliable, cost-effective gas purchases in accordance with gas purchasing plan;ii. Compliance with the Gas Supply and S&T Risk Management Procedures; and iii. Compliance with the Information Sharing and Access Policy for purchases of storage and transportation capacity between the legacy utilities.	Front, Mid and Back Office reporting structures and responsibilities are not appropriately segregated, which can increase the risk for improper recording of transactions and increase the opportunity for fraudulent activity not being detected.	1. Revise responsibilities and update Gas Supply Procedures 2. Review and update of organizational structure	Closed
	Risk Control compliance monitoring and reporting process excludes gas purchase transactions recorded in SAP, related to legacy Union, as they do not have access to this data.	Risk Control will implement compliance monitoring of SAP transaction level data for EGI commodity forward transactions	Closed
	Deals can be modified in SAP without prompting secondary review	Review of SAP transactions modified after release/approval	Closed
Damage Prevention Program Assess, based on risk, the design and operating effectiveness of key operational processes and controls within the Damage Prevention Program.	Risk Register is missing information on risk owners, associated hazards and internal controls	As the GDS risk register (RR) was recently combined, there was a direct transfer of some line items with terminology used in both legacy companies that may not perfectly align with the Framework Standard and many risks on the risk register are still in draft form. •The integration of the combined risk register is being done in a prioritized manner with High (H) and Very High (VH) risks being addressed first.To ensure that there is clear line of sight to H and VH risks, as well as some Medium (M), these are reported through the quarterly management review programs. •The GDS Risk Team will commit to reviewing the list of hazards used in the Risk Register (RR) to ensure they align with the Risk Management Framework Standard and/or Controlled Vocabulary.	Closed

Engagement Name	Finding	Management Action Plan	Finding Status
Damage Prevention Program Assess, based on risk, the design and operating effectiveness of key operational processes and controls within the Damage Prevention Program.	A defined process to enable the existence of 2nd party training records has not been fully developed	Damage Prevention's participation in the Locate Alliance Consortium (LAC) has an existing review process related to 2nd party training. In addition to the existing measures listed below, this MAP will enhance training records and assessments. •All Locate Service Provider (LSPs) complete LAC training –full training for new, refresher for existing •Training is reviewed at LAC monthly geographic and provincial meetings Through the MAP, Damage Prevention will complete the following: •Cross reference all Datapak/FRA users on an annual basis with received validated training records for all 2nd party locators •Where there is no Datapak/FRA access required by 2nd party locators, a quarterly assessment/random sample audit of completed locates will be conducted to ensure the appropriate training has been completed and up to date with company standards (minimum of 10% of locators annually) •Ensure the above is documented as a systematic & repeatable process for receiving all 2nd party locator training records, along with validation and cross referencing across EGI (GDS, Storage, Gazifere).	Closed
	4 of 5 Damage Prevention (DP) processes are undocumented or are partially documented	Formally document DP processes Formally document Common Element processes	Closed
	Controls are not linked to legal and regulatory requirements within the legal registry	As part of the ongoing Content Management Project, work is underway to map controls to requirements for integrated documents and the requirement to do so is included in the draft Content Management Governance document. As part of the continued implementation of the Ethics & Compliance Framework Standard on Requirements Management, the GDS Requirements Management Implementation Plan document also includes the requirement to map controls to requirements.	Closed
	Evidence to support that all IMS elements are assessed as part of management review needs enhancement	Ensure management oversight and assessment of the Integrated Management System Elements through the IMS Governance Framework and process: o Define roles and responsibilities for Element reporting and oversight in IMS Governance Standard o Provide quarterly element update to Top Management through the IMS Effectiveness Dashboard o IMS to facilitate quarterly Element touchpoint and provide update to relevant Stakeholders	Closed
GDS Control Room Management Assess whether the Gas Distribution & Storage (GDS) Control Room Management Plan (CRMP) and other Control Room Management (CRM) related processes are compliant with applicable regulatory requirements, including the Onshore Pipeline Regulations (OPR) and Pipeline and Hazardous Material Safety Administration (PHMSA). This included a review of the adequacy and effectiveness of the CRMP.	Verification of safety-related alarm points and descriptions has not been fully completed within timelines required by PHMSA.	• Establish process to verify PHMSA asset safety related alarms sets points and descriptions on an annual basis, not to exceed 15 months with Sr. Advisor. • Update CRM plan with new process and review new process with Sr. Advisor. • Complete the safety set point verification activity for PHMSA assets.	Closed
	The September 2020 monthly alarm review, that reviews alarms taken off scan for maintenance or operating activities in the field, did not identify changes from the prior month.	Expand off-scan monthly alarm review process documentation to outline what is included in the review, process for tracking/follow-up, and accountability. • Technical Specialist to document work process for future training purposes.	Closed
	Key reports used to complete the GDS monthly alarm review are not validated on a periodic basis to assess for completeness and accuracy.	• Control Room team will incorporate this finding into the development of the Quality Assurance Program.	Closed

Engagement Name	Finding	Management Action Plan	Finding Status
GDS Control Room Management Assess whether the Gas Distribution & Storage (GDS) Control Room Management Plan (CRMP) and other Control Room Management (CRM) related processes are compliant with applicable regulatory requirements, including the Onshore Pipeline Regulations (OPR) and Pipeline and Hazardous Material Safety Administration (PHMSA). This included a review of the adequacy and effectiveness of the CRMP.	Training related tools, including the training matrix and manual, require a more defined and repeatable review process to capture accurate and up to date information.	1. Update CRM Plan documentation to include review of training matrix in annual training program review. 2. The training manual (requirements overview) will not be included in this process and will be updated on a best efforts basis as it is considered supplemental training information.	Closed
	There is no documented Quality Assurance Program or second line of defense activities occurring for the GDS Control Room.	• Gas Control and QA will develop a Gas Control Quality Assurance Program (QAP) to facilitate second line assurance activities on the Control Room Management Program. This documented QAP will: • Review and incorporate existing assurance activities taking place within the CRM • Incorporate assessments, inspections and audits • Evaluate the effectiveness of the Management Program • Formally record corrective and preventative actions (CAPA) to facilitate action on these CAPAs and to assist with reporting • Requirements related to finding #3 - Key Reports used to complete monthly GDS Monthly Alarms not validated – will be covered off through the development of the QAP.	Closed
	Operator Interface Design manual has not been updated since 2014 to reflect changes to software and hardware.	SCADA team to update document and establish an annual review cycle. Any documentation changes should follow the SCADA MOC process.	Closed
	Resource planning activities do not take into consideration all resources required to support GDS Gas Control.	• Based on general objectives for Control Room Management purposes, identify functional areas required to support. • Communicate relevant resource requirements, as known, to the identified stakeholders, requesting that they confirm that required resources are available for 2021. • If sufficient resources are confirmed by relevant stakeholders, report on confirmation at Q2 2021 Management Review and TMR. • IMS will develop an evaluation of needs common process in 2021. • If insufficient resources are available, liaise with stakeholder group to identify a suitable 2021 plan and communicate at the Q2 2021 TMR.	Closed
Emergency Management Program Assess whether the Gas Distribution & Storage (GDS) Emergency Management (EM) Program is compliant with the Canada Energy Regulator (CER) and other Canadian federal and provincial regulatory requirements.	Emergency Planning Zones (EPZ) have not been consistently developed across all GDS Regions and those that have, are not being reviewed for ongoing completeness and accuracy	Incorporate the EPZ process in the EM Program.	Closed
	High and very high Emergency Management Program related risks have not been communicated to Senior Management	Integration of the Risk Register	Closed
	Emergency Management Program related assurance activities are occurring. These activities are not integrated through a systematic and coordinated Quality Assurance Program	Incorporate the Quality Assurance program process in the EM Program	Closed

Engagement Name	Finding	Management Action Plan	Finding Status
Emergency Management Program Assess whether the Gas Distribution & Storage (GDS) Emergency Management (EM) Program is compliant with the Canada Energy Regulator (CER) and other Canadian federal and provincial regulatory requirements.	Results of emergency management related inventory inspections at the regional level are not integrated into the GDS Emergency Management Program in order to provide a complete view of assurance of the Program	Incorporate the warehouse inventory inspection process in the EM Program.	Closed
Facilities Integrity - GDS Regional Assess Gas Distribution and Storage's (GDS) Facilities Integrity (FI), consisting of Facilities Integrity Management Program (FIMP) and Distribution Integrity Management Program (DIMP) related to Facilities, are properly designed and operating effectively to adequately govern operational risk at the Business Unit (BU) level in the Southeast Region and associated selected sites	Worksite hazard checklists are not consistently being documented and maintained in the Region, which can result in unmitigated hazards while performing job tasks and increased risk for injury.	• Communicate via email existing Hazard Assessment requirements and training until new integrated procedure comes into effect in 2022. • Communicate with Operations leadership to review the email details at monthly safety meetings. • Obtain supervisors confirmation they have reviewed the email communication and have executed all required actions. • Include standing agenda item to Monthly Leadership Team meetings to monitor and address follow-up from Hazard Assessment process.	Closed
	Following the lone worker processes at Legacy Union Gas is discretionary and does not require technicians to issue notification when working alone which can result in management not being aware of personnel-related incidents	• Communicate via email and confirm staff are aware of existing Lone Worker program until new integrated procedure comes into effect. • Communicate with Operations leadership to review the email details at monthly safety meetings. • Obtain supervisors confirmation they have reviewed the email communication and have executed all required actions. • Include standing agenda item to Monthly Leadership Team meetings to monitor and address follow-up from Lone Worker program.	Closed
	The most recently completed Annual Station Site Inspection completed at Cambridge East Station did not identify integrity of regulator building roof at Cambridge East Station is compromised, permitting water to accumulate within the building creating a safety hazard to personnel.	• The Cambridge East Station has been regraded and pooling of water was corrected during the audit. Southeast Region to conduct a follow-up assessment to determine additional roof improvements. The outcome of the assessment will be provided to the Asset Management group who will dictate timelines of repairs. • Communication to be issued to staff to ensure Annual Station Site Inspections are completed properly and follow up work orders are created when repairs are identified. • Include standing item to Station Supervisor monthly meetings to review work orders for follow-up work required.	Closed
	[redacted]	[redacted]	[redacted]
	A procedure for management of physical keys within the Region does not exist, which can result in unauthorized access to Regional facilities.	Southeast Region to work with GDS Security and Operations Governance team to leverage existing processes and implement a roll-out plan for regional key management.	Closed
	FIMP's purpose is to ensure pipeline facility systems are suitable for continued, safe, and reliable service and to comply with applicable regulations.	Implement the Integrity Change Request process, and any guidance document, that will be used as the inspection deferral procedure by FIMP. Implement QA activities related to Non-Destructive Examination (NDE) contractors for FIMP.	In Remediation

Engagement Name	Finding	Management Action Plan	Finding Status
Facilities Integrity - GDS Regional Assess Gas Distribution and Storage's (GDS) Facilities Integrity (FI), consisting of Facilities Integrity Management Program (FIMP) and Distribution Integrity Management Program (DIMP) related to Facilities, are properly designed and operating effectively to adequately govern operational risk at the Business Unit (BU) level in the Southeast Region and associated selected sites	Integrity inspections for pressure vessels and tanks have not been completed as required which may result in unmitigated integrity risks impacting safe and reliable operations and non-compliance with external requirements.	Refine the multi-year inspection plan, including units per year and budget, to complete the baseline inspection of pressure vessels and tanks.	Closed
	Integrity inspection procedures for assets relevant to FIMP have not been developed or implemented which may result in inspection activities performed inconsistently and unidentified integrity risks to assets.	• Complete the development of the Integrity Inspection procedures as part of the Integrity Documentation Project. • Communicate expectations to key stakeholders through email correspondence, communication meetings and training provided as requested.	Closed
	Inventory records for relevant Integrity assets at GDS are incomplete. This could result in FIMP's limited ability to locate similar asset types should an event occur requiring action or missed inspections.	• Develop and document the inventory of relief devices on pressure vessels as pressure vessel inspections are completed; this will result in a complete inventory for assets requiring inspection by FIMP on the same timeline in which all integrity inspections are completed, as outlined in the Management Action for Finding #2.	Closed
	Integrity inspection data available is limited or not available for all GDS stations which limits ability for FI to maintain compliance with relevant integrity inspection intervals and make quantitative decisions on risk across GDS	Refine the multi-year plan to complete integrity asset plans for FIMP stations, DIMP station categories, and regulatory required inspections.	Closed
Safety Management GDS Assessed Safety Management activities that govern operational risk at the Business Unit (BU) level, by region, and site. Assessed compliance with applicable regulations and guidelines, including but not limited to, Canada Energy Regulator (CER), Canada Labour Code (CLC), and Ontario Occupational Health and Safety Act (OOHSA).	A documented decision record supporting regulatory management of change (RMOC) to exclude these regulations from the Master Compliance Registry was not prepared.	Ethics & Compliance to create an RMOC in Maximo specific to applicability of the CLC and COHSRs to GDS and have a legal applicability decision documented within it.	Closed
	Powered Mobile Equipment (PME) procedures, which support safe operation of equipment, do not address all hazards which may result in a safety incident.	Define scope of PME for GDS in alignment with the Ontario Guideline for Safety Operations of Power Lift Trucks and evaluate existing documentation and control Document and implement a GDS PME program (considering accountabilities, design, hazard identification and control, maintenance, purchasing as applicable).	Closed
	GDS Safety Management Program does not include requirements for journey management planning which may increase hazards and driving incidents.	Review Enterprise Journey Management Plan (JMP) and develop guidance for GDS employees. As part of the implementation, develop documentation for requirements, roles and accountabilities, tools and training. Implement full GDS JMP Program.	Closed
	Requirements to verify evidence of variance action plans, or corrective actions, are not implemented.	Develop a process for tracking and verifying medium and high-risk contractor variance plans, including completion and closure of action plans. Review and document the approval process for variance plans, in alignment with the Enterprise CSM specification. Implement, train, and establish a plan to monitor.	Closed
	Oversight requirements to monitor contractor workers' compliance with standards are not defined which may result in inconsistent contractor oversight and potential non-compliance	Align GDS CSM Standard to Enterprise CSM Specification Implementation of CSM Standard changes	Closed

Engagement Name	Finding	Management Action Plan	Finding Status
Safety Management GDS Assessed Safety Management activities that govern operational risk at the Business Unit (BU) level, by region, and site. Assessed compliance with applicable regulations and guidelines, including but not limited to, Canada Energy Regulator (CER), Canada Labour Code (CLC), and Ontario Occupational Health and Safety Act (OOHSA).	Human Resources Training and Development self-identified: The Workday transformation reduced five employee learning systems across the organization into Workday and Veriforce. Workday training records are reporting incomplete or overdue training for employees that is not required. This may result in employees completing training that is not required.	Engage business and safety training teams to identify data issues Including: – Set review requirements, provide BUs and Corporate and Central Functions training teams with an issue template; define an approach for each group to work with data analysts from TIS. – Review the process and recommend priorities for data correction – With support from TIS, HR Solutions will analyze data and consult with Workday Inc. to determine strategies to correct data – Develop the scope, design and resource strategies for the remediation plan – Implement data correction actions including prioritization	Closed
	Working Alone Procedures are incomplete	As part of the GDS safety program integration develop a GDS lone worker program. Document and Implement the requirement for a documented hazard assessment when working alone in the field as part of the hazard assessment program integration Develop and implement an integrated Working Alone program for GDS which includes all applicable roles and associated controls.	In Remediation
	A re-assessment of workplace violence hazards has not been performed since 2018, which may lead to an increased risk of violence and potential non-compliance with health and safety regulations.	Document and implement the Workplace Violence Hazard Re-Assessment process with associated roles and responsibilities	Closed
	Hazardous Waste Storage Guide provides guidance on the required design of designated storage areas and how to store hazardous waste. Waste storage at three sites did not meet requirements, which may result in an environmental or safety incident	Resolve all the observations documented in the Finding. Appoint a minimum of one “Hazardous Waste Supervisor” at each Designated Hazardous Waste Site, Provide Safety and Reliability Environmental course.	Closed
	GDS Operations Services requires the completion of a deferral procedure when assets are not inspected or maintained according to schedule. An equipment inspection deferral and mitigation plan was not completed as required by Operations Services which may result in safety, reliability, and operational risk.	Northern Region Station Operations Manager will provide a process review for the Station Operations Supervisors for the submission of “Request for Variance” when Operating Standard work will not be completed within the compliance timeframe.	Closed
	Supervisors assign employee training based on risk or role in the GDS Environmental Health and Safety (EHS) Training Selection Tool. Employees in the same role were assigned different environment related training courses	EHS Training Selection Tool and Mandatory training requirements will be reviewed at the monthly Safety Round Table in February 2022 with all people leaders in the region. All supervisors in the region will review.	Closed

Engagement Name	Finding	Management Action Plan	Finding Status
Safety Management GDS Assessed Safety Management activities that govern operational risk at the Business Unit (BU) level, by region, and site. Assessed compliance with applicable regulations and guidelines, including but not limited to, Canada Energy Regulator (CER), Canada Labour Code (CLC), and Ontario Occupational Health and Safety Act (OOHSA).	Quality Assurance Program (QAP) requires a work order to be submitted when unable to immediately repair a damaged valve box. A maintenance work order was not submitted for a corroded valve box, which prevents damage to valve gears, at the Barnett Road Metering Station. Damaged equipment may result in an increased risk of a safety or operational incident occurring.	• Provide documented refresher for front line Station Techs, at a monthly team meeting, on the use of PM10 workorders in SAP to capture required Maintenance.	Closed
	[redacted]	[redacted]	[redacted]
	GDS does not have sufficient resources to implement and maintain the SMP across the business unit which has resulted in the Program not meeting internal and external requirements.	The finding will be remediated as follows: • Perform budget assessment – currently pending approval • Conduct manpower evaluation – currently pending approval to obtain additional resources that will be distributed across the BUs • Undergo recruitment and hiring process • Onboard successful candidate(s) • Implement Security Training Program	Closed
Security Management Program Assess the Security Management Program (SMP) activities that manage operational risk at the enterprise and business unit (BU) level, by region and site. Assess compliance with applicable regulations, including, but not limited to, Canada Energy Regulator (CER), US Pipeline and Transportation Security Administration (TSA) from the US Department of Homeland Security.	GDS Roles and responsibilities for all stakeholders implementing and executing security activities have not been defined and documented in the SMP or supporting documentation.	The finding will be remediated as follows: • A new Enterprise Security SMP is being developed that will document roles and responsibilities across all the business units, for both Enterprise Security and other stakeholders involved in Security activities. The updated SMP will also address the continual improvement process with operations by ensuring assurance quality checks, maintenance requirements and tracking, SVA recommendation closures as well as GAP closure plans from Audits, as well as integrating current and the development of additional assurance activities. • The target date for approval and publication is June 1, 2022, with an implementation date of June 1, 2023. • Roles and responsibilities will be communicated to the BUs via kick-off and planning meetings.	Closed
	GDS A Security Management training program, as required by CSA Z246.1, has not been developed and implemented, including identification and evaluation of competencies for stakeholders responsible for implementing security activities.	The Enterprise Security SMP has been developed for the enterprise. It documents procedures and standards, including a training program, and competencies for roles tasked with executing security activities, as required by CSA Z246.1.	Closed

Engagement Name	Finding	Management Action Plan	Finding Status
Security Management Program Assess the Security Management Program (SMP) activities that manage operational risk at the enterprise and business unit (BU) level, by region and site. Assess compliance with applicable regulations, including, but not limited to, Canada Energy Regulator (CER), US Pipeline and Transportation Security Administration (TSA) from the US Department of Homeland Security.	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	The GDS Management of Change process has not been implemented for Corporate Security, as required by Onshore Pipeline Regulations, which can result in changes related to Security not being understood	• Review MOC requirements and update change triggers list to reflect any identified gaps.	Closed
	GDS All security incidents are not being reported to program owners, as required by CSA Z246.1. The Security Incident Management Process is not executed as developed which has resulted in incidents not communicated to key internal	• The Enterprise Security SMP has been developed for the enterprise. It documents procedures and standards, including a training program, and competencies for roles tasked with executing security activities, as required by CSA Z246.1. • It has a target publish date of 1 June 2022 and an implementation date of 1 June 2023. The current processes will be updated to reflect the process that the BU is following to manage security incidents. • The Enterprise Security SMP will include provisions to address the roles and responsibilities for all stakeholders implementing and executing security activities, tools used for reporting requirements, and document retention procedures. SOPs will be updated to address BU specific activities performed. A reconciliation should be completed to confirm that all incidents reported have been captured. (Documented in Enterprise Security SMP Annual Review). • The target date for approval and publication is 1 June 2022, with an implementation date of 1 June 2023.	Closed
	GDS Security countermeasures to respond to temporary security threats are not identified and tested, which can result in impractical or inappropriate countermeasures established for identified temporary threat escalation levels.	• Schedule and test updated threat levels through drills and exercises. • Update the Management Program (MP-06) and Enterprise Security Management Governance documents to address countermeasures and reference new TSA guidelines more thoroughly on criticality.	Closed
	[redacted]	[redacted]	[redacted]

Engagement Name	Finding	Management Action Plan	Finding Status
Security Management Program Assess the Security Management Program (SMP) activities that manage operational risk at the enterprise and business unit (BU) level, by region and site. Assess compliance with applicable regulations, including, but not limited to, Canada Energy Regulator (CER), US Pipeline and Transportation Security Administration (TSA) from the US Department of Homeland Security.	GDS A lesson learned process from incidents has not been documented and implemented as required by CSA Z246.1 for the Security Management Program which leads to an inability to identify opportunities for continual improvement.	• Incorporate a lessons learned section into the new Enterprise Security SMP • Document and Track Drills and Exercises Enterprise Wide. • Incorporate Security Drills into existing Emergency response exercises.	Closed
	GDS Document classification and retention activities have not been executed as designed in the Security Management Program. This can result in unauthorized access to security sensitive information.	• Update the Security Management Program document classification naming convention at the next document review. • Review key security activity templates (e.g. SVA report template) to confirm it includes accurate document classifications per the procedure. • Establish periodic review cycle to spot-check that required document classifications have been applied to security sensitive information.	Closed
	GDS Security Management Program related assurance activities are not integrated through a systematic and coordinated Quality Assurance Program which leads to an inability to identify opportunities for continual improvement.	Within the new Security Governance Document, establish and implement a Quality Assurance Program to provide, support and coordinate assurance activities on behalf of the Security Management Program. This would include integrating existing and developing additional assurance activities.	Closed
	GDS The current Regulatory Management of Change process is not triggered until a new or updated regulatory requirement is issued, which may result in the Security Management Program being out of compliance with regulatory requirements	Regulatory Affairs to establish a process to coordinate engagement with existing and future internal Enbridge representatives on applicable CSA committees where the standards have regulatory compliance implications. Process to include accountability for requesting the initiation of a RMOC by Ethics & Compliance where compliance is required on standard issuance date.	Closed
	GDS Minimum physical security requirements, which is the baseline physical security standard for all facilities as identified in the Security Management Program, does not include security measures required by CSA Z246.1 and TSA guidelines	• Enterprise Security will periodically participate in inspections. • Enterprise Security will review inspection checklists.	Closed
	[redacted]	[redacted]	[redacted]

Engagement Name	Finding	Management Action Plan	Finding Status
Security Management Program Assess the Security Management Program (SMP) activities that manage operational risk at the enterprise and business unit (BU) level, by region and site. Assess compliance with applicable regulations, including, but not limited to, Canada Energy Regulator (CER), US Pipeline and Transportation Security Administration (TSA) from the US Department of Homeland Security.	[redacted]	[redacted]	[redacted]
	GDS Management of Change process was not implemented for a temporary change in Environmental Hazardous Waste manifests	Review existing tools and programs for opportunities to address temporary accommodations (ex: MOC Change Triggers List, Content Management Program, Environmental procedures).	Closed
	Regional Hazardous Waste manifests were unsigned or signed by a third-party carrier on behalf of Enbridge in deviation of the requirements which could result in potential non-compliance.	Communicate the requirements to complete hazardous waste manifests using the OPS_STO Communication Package	Closed
	Safety forms, designed to enable workers to identify and mitigate hazards, are not fully documented, which may lead to associated hazards materializing increasing the risk for injury.	Share audit findings with Operations Managers and cascade to respective teams. • Provide a reminder/refresher in monthly team/safety meetings to employees of proper form and relevant paperwork completion. • In addition to MAP activities, the business unit will also endeavour to identify opportunities for paperless project documentation retention and implementation within new GDS/Enterprise work-management systems - i.e., Maximo or other (AWS Phase 2 – 2021 and AWS Phase 3 – 2023/2024).	Closed
	Training did not occur for two workers using equipment and instances of expired training were observed, which decreases worker awareness and could result in a potential incident.	1.During future internal audits, Storage & Transmission Operations (STO) will ensure that supervisors and employees participating in audits have met current training requirements relevant to the tours being led. To do this, we will obtain detailed scope of what needs to be observed in order to coordinate resources based on skill set, training, and job function. 2. Safety will complete the following Management Action Plan to address this finding: • Recommunicate the use of PowerBI until its retirement date and then transition to Workday learning to monitor training and the status of courses. • Communicate the requirements to complete training before they expire and re-enforce that previous legacy training completion practices (end of calendar year expirations) are no longer in place.	Closed
GDS Environmental Protection Program Assess Environmental Protection Program (EPP) activities that govern operational risk at the Business Unit (BU) level, by region and site.	Corrective actions for recommendations from 2020 and 2021 regulatory third-party waste audits were not developed in accordance with Assurance standards.	Confirmation that the action plan has been implemented as prescribed and that the finding has been remediated.	Closed
	GDS EPP roles and responsibilities have not been developed for all environmental activities (including, but not limited to, abandonment activities and water) which may result in potential environmental incidents and non-compliance.	Updated Environmental Protection Program	Closed

Engagement Name	Finding	Management Action Plan	Finding Status
GDS Environmental Protection Program Assess Environmental Protection Program (EPP) activities that govern operational risk at the Business Unit (BU) level, by region and site.	Ontario Water Resources Act applies to water taking permitting, reporting, and exemptions requirements for domestic and industrial use.	Review regulation and applicability to well water use at GDS owned buildings and based on review, assess if actions are required.	Closed
	Multi-Sector Air Pollutants (MSAPR) and Methane Emission regulations were published in 2016 and 2018, respectively. Processes and procedures to enable compliance with these regulations have not been implemented and/or approved.	Confirmation that the action plan has been implemented as prescribed and that the finding has been remediated.	Closed
	GDS risk register contains 17 environmental hazards, we identified potential hazards that have not been mapped to the risk register. An inventory without identified and potential hazards could lead to potential non-compliance.	Confirmation of review of the risk evaluation document	In Remediation
GDS Regional Audit - [redacted] All Protection Programs are included in our engagement, with a focus on higher risk areas as determined through input from the Business Unit, internal and external information.	Physical security measures at six of eight sites are not in accordance with requirements. This could result in unauthorized entry to GDS facilities and potential non-compliance with regulatory standards.	[redacted] Region to work with GDS Security and Operations Governance team to leverage the new Guidance - Key and Access Code Management (to be published by Security Program on Nov 1, 2022) and implement a roll-out plan for regional key management [redacted] Operations Manager to assign responsibility and develop process to ensure PIN code is changed on regular basis Engage GDS Security and REWS to create a plan to develop a process to review the accuracy of GDS access logs and identification of accountable parties. [redacted] Stations Operations Manager will coordinate refresher training on monthly site inspections with Station Technicians.	In Remediation
	Storage and labeling of hazardous substances at five of eight sites are not in accordance with requirements. This may pose safety and fire hazards and potential regulatory non-compliance.	Revised monthly site inspection checklist with additional emphasis on hazardous material storage and provide training.	Closed
	Pre-use and annual inspections are not complete on three power mobilized equipment as required by the Construction & Maintenance Manual.	[redacted] Operations Manager will coordinate refresher training on equipment and vehicle pre-use inspection requirements with all [redacted] field workers and supervisors in consultation with Fleet.	Closed
	Monthly station site inspection checklist was not documented or completed at two of eight sites as required by major station visual inspection procedures.	[redacted] Station Manager will have a meeting with Stations Team to reinforce monthly site inspection procedures.	Closed
GDS Pipeline Integrity Program Assess Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP) activities that govern operational risk at the BU level, by region and site	GDS was unable to demonstrate inspections have been conducted on piping exposed to atmosphere for TIMP and DIMP.	The following three actions will be completed by Engineering: - Update Corrosion Standard to include a Visual Inspection Table that defines and includes risers and references other applicable visual inspections. - Develop a method to demonstrate the ability to extrapolate a riser inventory based on associated meter sets as defined in Maximo. - Develop procedure to maintain and communicate current inventory of known Arial Crossings.	In Remediation

Engagement Name	Finding	Management Action Plan	Finding Status
GDS Pipeline Integrity Program Assess Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP) activities that govern operational risk at the BU level, by region and site	Deferral process, used to delay or defer an integrity verification or damage mitigation activities, has not been documented per IMFS.	Included deferral as a requirement in other Integrity documentation. Develop a separate swim-lane process for integrity deferrals that documents specific stakeholders and accountabilities and approval levels.	In Remediation
	Unused coated pipe was observed to be stored without cover or protective end caps at 2 of 4 Depots (50%).	Operations-Storage-Engineering (OPS-STO-ENG) communications package slide outlining the storage requirements and reminding these need to be followed Eastern Region will transition emergency stock to Niagara, which adheres to C&M 35.8.5 Pre-Tested Emergency Pipe Stock - Update Emergency Program Office Manual to reflect the emergency stock locations.	In Remediation
	GDS Quality Manual (QM) references Audit to describe activities carried out by QM Core Audit, however activities do not meet expectations outlined in the Enbridge Framework Standard – Audit	Risk Acceptance in the interim until next review cycle of the QM Core process. Gap was known to GDS and already planned to be closed out as part of the IMS Assurance Optimization Project and QM Integration Work.	In Remediation
	Safety Case Review procedures does not provide guidance on barrier effective assessment and does not capture input summary from other assessments.	GDS Integrity Safety Case will review outputs to ensure safety case assessment guide and safety case review template have been implemented and followed.	In Remediation
	From 2019 to 2021, the annual Cathodic Protection survey for 352 of 66,057 (0.5%) instances test points were not completed.	Continue to review any test points that have not been surveyed or not remediated and document reasons utilizing the Request for Variance (RFV), to include exceptions noted as a result of this audit.	In Remediation
	Cathodic Protection for 35 out of 684 (5%) TIMP and DIMP rectifiers were not inspected once every two months, as required by GDS' corrosion control standard.	New Lantern application is scheduled for go live Q2 2023 and will provide a consolidated view of corrosion dataset for GDS, which support work required and improve data quality.	In Remediation
	Four of 25 (16%) sampled cathodic protection test points not meeting protection criteria, were not remediated or have a follow-up work order within six months of inspection.	Corrosion Operations will review RFV reasons and update process based on justification.	In Remediation
GDS Regional Audit - [redacted] We performed risk-based Specified Procedures to assess operating effectiveness of key operational processes of Enbridge's other Protection Programs.	Construction & Maintenance utility trailer dispatched out of [redacted] did not have adequate ventilation for storage and transport of gasoline, nitrogen, and propane.	1. The trailer will be modified in the short term to provide ventilation and allow continued use. This work will be completed by Jan. 31, 2023. 2. The trailer will be on the list for replacement as part of the procurement process. It will be prioritized against other needs through the asset management process. This will be completed by Mar. 31, 2023.	In Remediation
	Combustible and flammable products at five of twelve sites were not stored in accordance with internal standards, which may pose safety and fire hazards.	1.Remediate non-conformance and hold safety meeting at each identified location to communicate labelling and storage requirements for combustible and flammable materials. Employees to sign off attendance at meeting. 2. Documentation related to this finding (storage requirements for combustible and flammable materials) will be updated as part of ongoing integration work within GDS. A previously identified integration project is currently being planned to address this.	In Remediation

Engagement Name	Finding	Management Action Plan	Finding Status
GDS Regional Audit - [redacted] We performed risk-based Specified Procedures to assess operating effectiveness of key operational processes of Enbridge's other Protection Programs.	Pipeline marker emergency numbers at one point on the ROW were not labeled and identified on NPS 12 CER NGTL-[redacted] per internal standards.	Replace, add, or update line markers and signage along the route will be completed by the South Valley crews. The upgrades will be completed as per PT-17-9C07-11C4 "Pipeline Markers Procedure".	In Remediation
	All emergency pipe at [redacted] was not fit for use as there was evidence of external corrosion.	1. [redacted] transitioned emergency stock to Niagara. This adheres to C&M 35.8.5 Pre-Tested Emergency Pipe Stock. – Emergency stock for CER lines is already stored in Niagara and is correctly referenced in relevant documentation. 2 [redacted] will follow documentation review and publication cycle to update relevant documentation in 2023 with publication in Q1 2024.	In Remediation
	ROW vegetation control requirements on NPS 12 CER NGTL-[redacted] were not met in accordance with external regulatory requirements.	Contractor will perform the work on the 6-7 kilometers of ROW to be cleared.	In Remediation
	Hazardous waste at three of twelve sites was not stored, labeled, or disposed according to internal standards.	Refresher training for Operations Supervisors completed by Regional Safety Advisor when they are in the role.	In Remediation
	Solid and recyclable waste at three of twelve sites included mixed waste streams and improper labeling per internal standards. Improper separation and labeling of waste may result in potential environmental damage.	Safety meeting with all relevant staff to emphasize the importance of not mixing waste streams.	In Remediation
	Physical security measures at four of twelve sites were not in accordance with internal standards. This could result in unauthorized entry to facilities.	[redacted] Management to remediate the following: – Security Fencing issues at [redacted] Depots and Gate Stations. – Replace security signage at [redacted] Depot. – Remediate Vegetation concerns at [redacted] Station, [redacted] Depot, [redacted] Gate Station, and [redacted] Depot.	In Remediation
	Security plans have not been developed to mitigate current and evolving biological hazards at the job site due to transient population in the area.	The new Sharps Management Program for GDS will be released (PT-2B-1108-0017 Sharps Safe Handling and Disposal Procedure) and communicated in Q1 2023.	In Remediation
	Load ratings were not posted on storage racks at two of twelve sites as required by internal standards. This could result in stocking items above load capacity, leading to potential structural failure and workplace injuries.	1.Engage Real Estate and Workplace Services (REWS) to validate load sticker requirements and communicate them to all relevant stakeholders, including those involved in new construction. 2. Engage REWS to apply load rating labels across all racking in the [redacted] Monthly JHSC inspections will monitor progression of this item until close out.	In Remediation
	General workplace housekeeping safety hazards were observed at nine of twelve sites which did not confirm to internal standards. Poor housekeeping may result in safety hazards that can lead to injuries to workers.	Region to remediate specific items noted in finding, followed by JHSC workplace inspection to monitor conformance post-remediation. Log Safety Leadership in Action by [redacted] Management to confirm remediation.	In Remediation

Engagement Name	Finding	Management Action Plan	Finding Status
GDS Regional Audit - [redacted] We performed risk-based Specified Procedures to assess operating effectiveness of key operational processes of Enbridge's other Protection Programs.	Recent JHSC inspections did not identify hazards and at-risk conditions present onsite per internal standards.	1. Deliver JHSC Workplace Inspection training for JHSC members. Training will include hazards that may be found during workplace inspections, inspection requirements, and documentation expectations. 2. Review JHSC monthly inspection requirements highlighting the importance and significance of the purpose of inspections, timely identification of non-conformances and actioning non-conformances identified.	In Remediation
GDS Regional Audit - GTA East Region We performed risk-based Specified Procedures to assess operating effectiveness of key operational processes of Enbridge's other Protection Programs.	Monthly JHSC inspections at TOC and Peterborough Depot are not identifying all hazards present onsite. Additionally, no evidence to support September 2022 inspections were performed for these Depots. This can lead to non-conformances at site	Review JHSC monthly inspection requirements with all members Deliver JHSC Workplace Inspection training for JHSC members.	In Remediation
	Combustible and flammable materials at the Technology and Operational Centre (TOC), Peterborough Depot and Pickering Gate Station are not labelled or stored safely and may increase potential fire hazards and risk of workplace injuries.	Remediate items noted and hold tailgate about labelling and storage requirements for combustible and flammable materials. Documentation related to this finding (storage requirements for combustible and flammable materials) will be updated as part of ongoing integration work within GDS	In Remediation
	Internal safe work practices related to personal protective equipment and pressurized equipment were not being followed at one of three construction and maintenance sites visited. This could result in potential workplace injuries.	Hold tailgate for safe work practices, develop tool guide for Kravitch tool, and share corrective actions of audit.	In Remediation
	Chemical and hazardous waste at TOC, Peterborough Depot and Campbellford Gate Station was not stored and labeled in accordance with internal requirements. This may result in potential workplace injuries and / or environmental contamination.	Remediate hazardous waste and chemical storage areas and hold tailgate to review hazardous waste and chemical storage requirements	In Remediation
	Load ratings were not posted on all storage racks at both TOC and Peterborough Depot. This could result in stocking items above load capacity of the shelving, leading to potential structural failure which could result in workplace injuries.	Real Estate and Workplace Services (REWS) to validate and communicate load sticker requirements Engage REWS to apply load rating labels across all racking in the GTA East Depots	In Remediation
	Site housekeeping matters were noted with respect to safety and security at the TOC and Peterborough Depots, including materials and equipment at the Peterborough Depot warehouse blocking access to spill kit and fire extinguishers and multiple unsecured ladders at both locations. Poor housekeeping may result in workplace injuries or unauthorized entry.	Remediate specific items noted in finding. Monthly JHSC inspections will monitor compliance post remediation. Log Safety Leadership in Action (SLiA) by GTA East Management to confirm remediation	In Remediation

Engagement Name	Finding	Management Action Plan	Finding Status
GDS Regional Audit - GTA East Region We performed risk-based Specified Procedures to assess operating effectiveness of key operational processes of Enbridge's other Protection Programs.	No evidence was provided to support that quarterly spill kit inspections have been conducted at TOC and Peterborough Depot. This may result in inadequate supplies being on hand to contain a leak which could lead to a potential spill not being contained in a timely manner.	Create spill kit inventory and engage with REWS to complete depot spill kit inspections	In Remediation
	Scrap metal waste area at Peterborough Depot included mixed waste streams and was stored outside of a storage bin. This does not allow for easy offsite removal and increases risk of workplace injuries and potential environmental hazards.	Remediate scrap metal area and hold tailgate meeting for not mixing waste streams	In Remediation
	Two emergency exit gates at Markham Gate Station and one at Bowmanville Gate Station did not allow for free egress due to unlevel ground and / or uncontrolled vegetation outside the facility.	Clear vegetation outside emergency exits at Bowmanville and Markham Gate and provide training on the monthly visual inspections	In Remediation
	Periodic inspections of emergency response equipment, including fire extinguishers, eye wash stations, first aid kits and automated external defibrillator (AEDs), have not been performed in accordance with internal requirements.	Engage REWS to work with a new facilities management company to deliver monthly inspections for emergency response equipment. Documentation related to this finding (inspection frequency for emergency response equipment) will be updated as part of ongoing integration work within GDS.	In Remediation
GDS Construct Asset Lifecycle Phase Assess whether Projects construction processes and controls are adequately designed in alignment with relevant GDS IMS and Protection Program requirements and have been appropriately implemented. Review the Sarnia Industrial Line Reinforcement (SILR) project to assess the operating effectiveness of Projects construction processes and controls.	There was no Management of Change (MOC) documentation for the changes impacting the SILR project.	Issue a Design Basis Memorandum (DBM) User Guide and a DBM Template. Projects agrees with the finding and will determine a suitable MOC process by July 22, 2022.	Closed
	The required Excavation Checklist was not completed or not signed off for seven of nine days sampled.	Review the Ground Disturbance Permit (Excavation Checklist) requirements with relevant Projects personnel. Perform monthly audit checks to ensure requirements are met making necessary process improvements. Create a filing system at each project site to retain both hard and digital copies of completed Excavation Checklists.	Closed
	Two minor Level 1 property damage incidents on the SILR project were not recorded in EnCompass.	SILR Project Manager will record the two minor property damage incidents in EnCompass. Projects will work with Safety to determine and implement a training plan.	Closed - Management Accepted the Risk
	A quality incident occurred where a NPS 20" ball valve installed at the Dow Valve Site did not seal. Neither a QIN nor QER was issued which resulted in non-conformance and inaccurate and incomplete quality incidents data.	Quality Management to issue QER. The Quality Management Office (QMO) team will clarify requirements in the Quality Incident Response Procedure.	Closed

Engagement Name	Finding	Management Action Plan	Finding Status
GDS Regional Audit - [redacted] We performed risk-based Specified Procedures to assess operating effectiveness of key operational processes of Enbridge's other Protection Programs.	Monthly JHSC inspections at 2 of 2 sampled Depots [redacted] re not identifying all hazards present onsite. Additionally, no evidence to support September 2022 inspections were performed at these Depots.	Review JHSC monthly inspection requirements with all members Deliver JHSC Workplace Inspection training for JHSC members.	In Remediation
	Combustible and flammable materials at [redacted] are not stored safely which may increase potential fire hazards and risk of workplace injuries.	Remediate combustible and flammable item storage and conduct training to staff Documentation related to this finding (storage requirements for combustible and flammable materials) will be updated as part of ongoing integration work within GDS	In Remediation
	Load ratings were not posted on all storage racks at [redacted] This could result in stocking items above load capacity of the shelving, leading to potential structural failur	Engage Real Estate and Workplace Services (REWS) to validate load sticker requirements and communicate them to all relevant stakeholders, including those involved in new construction. Engage REWs to review all shelving and apply required load ratings.	In Remediation
	Site housekeeping matters were noted with respect to safety and security at [redacted] including improper storage of equipment creating tripping hazards and eye wash station at [redacted] blocked by items stored in the warehouse. Poor housekeeping may result in workplace injuries or unauthorized entry.	Remediate specific items noted in finding. Managers to complete inspection and log SLiA to confirm remediation.	In Remediation
	No evidence was provided to support that quarterly spill kit inspections have been conducted at [redacted] This may result in inadequate supplies being on hand to contain a leak which could lead to a potential spill not being contained in a timely manner.	Regional management to ensure completion of spill kits is completed by qualified inspector / vendor. Regional managers to log a SLiA to validate completion of inspections.	In Remediation
	Physical security measures at five of six facility sites visited are not in conformance with internal security requirements, including missing signage and inadequate fencing height. This increases the risk of unauthorized entry.	[redacted] Have stone added to reduce gaps along fence line. [redacted] Repair fence and add required signage. [redacted] – Remove items stored along the fence line. [redacted] – Add required signage. [redacted] – Fencing deficiencies to be reviewed under implementation of the new security corporate program. Update to be provided to Internal Audit on the plan go forward once assessment is complete.	In Remediation

Engagement Name	Finding	Management Action Plan	Finding Status
GDS Regional Audit - [redacted] We performed risk-based Specified Procedures to assess operating effectiveness of key operational processes of Enbridge's other Protection Programs.	One emergency exit gate at [redacted] did not allow for free egress due to malfunctioning panic hardware. One emergency exit gate at [redacted] led to a locked, fenced-in area and inability to reach the muster point.	Repair [redacted] emergency exit. Remove [redacted] door emergency exit sign as there are sufficient other egress options. Manager to enter a SLiA confirming completion of remediation actions. Provide refresher training for Major Station Techs on monthly visual inspections and what items to look for. Documentation related to the inspection of Gate / Feeder Station emergency gates will be updated as part of the Station Tech refresher training.	In Remediation
	Periodic inspections of emergency response equipment, including fire extinguishers, eye wash stations, first aid kits and automated external defibrillator (AEDs), have not been performed in accordance with internal requirements.	Update internal documentation for emergency equipment inspections frequency Engage REWS to work with a new facilities management company to deliver monthly inspections for Toronto Region emergency response equipment.	In Remediation

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1

Question(s):

Please provide Enbridge's most recent business plan (or similar document if there is no formal business plan).

Response:

Please see Attachment 1 for the Gas Distribution & Storage presentation from the 2023 Enbridge Day Investment Community Conference, March 1, 2023.

Gas Distribution & Storage

Michele Harradence
President of Gas Distribution & Storage

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Legal notice

Forward Looking Information

This presentation includes certain forward-looking statements and information (FLI) to provide potential investors and shareholders of Enbridge Inc. (Enbridge or the Company) with information about Enbridge and its subsidiaries and affiliates, including management's assessment of their future plans and operations, which FLI may not be appropriate for other purposes. FLI is typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe", "likely" and similar words suggesting future outcomes or statements regarding an outlook. All statements other than statements of historical fact may be FLI. In particular, this presentation contains FLI pertaining to, but not limited to, information with respect to the following: Enbridge's strategic plan, priorities and outlook; 2023 financial guidance and near and medium term outlooks, including average annual growth, and projected EPS, DCF per share and adjusted EBITDA, and expected growth thereof; expected dividends, dividend growth and dividend payout policy; expected supply of, demand for, exports of and prices of crude oil, natural gas, natural gas liquids (NGL) , liquified natural gas (LNG) and renewable energy; energy transition and our approach thereto; environmental, social and governance (ESG) priorities, practices and performance, including greenhouse gas (GHG) emission reduction goals and approach and diversity and inclusion goals; industry and market conditions; anticipated utilization of our assets; expected EBITDA; expected DCF and DCF per share; expected future cash flows; expected shareholder returns and returns on equity; expected performance of the Company's businesses, including customer growth and organic growth opportunities; financial strength, capacity and flexibility; financial priorities and outlook; expectations on sources of liquidity and sufficiency of financial resources and funding plan; expected debt to EBITDA outlook and target range; expected costs and in-service dates for announced projects, projects under construction and system expansion, optimization and modernization; capital allocation priorities; investment capacity; expected future growth, including secured growth program, development opportunities and low carbon and new energies opportunities and strategy; expected future actions of regulators and courts and the timing and anticipated impact thereof; and toll and rate case proceedings and frameworks, including with respect to the Mainline and Gas Distribution and Storage, and anticipated timing and impact therefrom.

Although we believe that the FLI is reasonable based on the information available and processes used to prepare it, such statements are not guarantees of future performance and you are cautioned against placing undue reliance on FLI. By its nature, FLI involves a variety of assumptions, known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by the FLI, including, but not limited to, the following: the expected supply of, demand for and prices of crude oil, natural gas, NGL, LNG and renewable energy; energy transition, including the drivers and pace thereof; global economic growth and trade; anticipated utilization of our assets; exchange rates; inflation; interest rates; the COVID-19 pandemic and the duration and impact thereof; availability and price of labour and construction materials; the stability of our supply chain; operational reliability and performance; customer, regulatory and stakeholder support and approvals; anticipated in-service dates; weather; announced and potential acquisition, disposition and other corporate transactions and projects, and the timing and benefits thereof; approval of the Company's board of directors of announced transactions and projects; governmental legislation; litigation; credit ratings; hedging program; expected EBITDA and adjusted EBITDA; expected earnings/(loss) and adjusted earnings/(loss); expected future cash flows; expected future DCF and DCF per share; estimated future dividends; financial strength and flexibility; debt and equity market conditions; general economic and competitive conditions; the ability of management to execute key priorities; and the effectiveness of various actions resulting from the Company's strategic priorities.

We caution that the foregoing list of factors is not exhaustive. Additional information about these and other assumptions, risks and uncertainties can be found in applicable filings with Canadian and U.S. securities regulators. Due to the interdependencies and correlation of these factors, as well as other factors, the impact of any one assumption, risk or uncertainty on FLI cannot be determined with certainty. Except to the extent required by applicable law, we assume no obligation to publicly update or revise any FLI made in this presentation or otherwise, whether as a result of new information, future events or otherwise. All FLI in this presentation and all subsequent FLI, whether written or oral, attributable to Enbridge, or any of its subsidiaries or affiliates, or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

Non-GAAP Measures

This presentation makes reference to non-GAAP and other financial measures, including earnings before interest, income taxes, depreciation and amortization (EBITDA), adjusted EBITDA, adjusted earnings and adjusted earnings per share (EPS), distributable cash flow (DCF) and DCF per share and debt to EBITDA. Management believes the presentation of these metrics gives useful information to investors and shareholders as they provide increased transparency and insight into the performance of the Company. Adjusted EBITDA represents EBITDA adjusted for unusual, infrequent or other non-operating factors on both a consolidated and segmented basis. Management uses EBITDA and adjusted EBITDA to set targets and to assess the performance of the Company and its business units. Adjusted earnings represent earnings attributable to common shareholders adjusted for unusual, infrequent or other non-operating factors included in adjusted EBITDA, as well as adjustments for unusual, infrequent or other non-operating factors in respect of depreciation and amortization expense, interest expense, income taxes and non-controlling interests on a consolidated basis. Management uses adjusted earnings as another measure of the Company's ability to generate earnings and uses EPS to assess the performance of the Company. DCF is defined as cash flow provided by operating activities before the impact of changes in operating assets and liabilities (including changes in environmental liabilities) less distributions to non-controlling interests, preference share dividends and maintenance capital expenditures, and further adjusted for unusual, infrequent or other non-operating factors. Management also uses DCF to assess the performance of the Company and to set its dividend payout target. Debt to EBITDA is used as a liquidity measure to indicate the amount of adjusted earnings available to pay debt (as calculated on a GAAP basis) before covering interest, tax, depreciation and amortization.

Reconciliations of forward-looking non-GAAP and other financial measures to comparable GAAP measures are not available due to the challenges and impracticability of estimating certain items, particularly certain contingent liabilities and non-cash unrealized derivative fair value losses and gains which are subject to market variability. Because of those challenges, reconciliations of forward-looking non-GAAP and other financial measures are not available without unreasonable effort.

The non-GAAP measures described above are not measures that have standardized meaning prescribed by generally accepted accounting principles in the United States of America (U.S. GAAP) and are not U.S. GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers. A reconciliation of historical non-GAAP and other financial measures to the most directly comparable GAAP measures is available on the Company's website. Additional information on non-GAAP and other financial measures may be found in the Company's earnings news releases or in additional information on the Company's website, www.sedar.com or www.sec.gov.

Unless otherwise specified, all dollar amounts in this presentation are expressed in Canadian dollars, all references to "dollars" or "$" are to Canadian dollars and all references to "US$" are to US dollars.

First-choice for Natural Gas Delivery

Critical & Cost Competitive

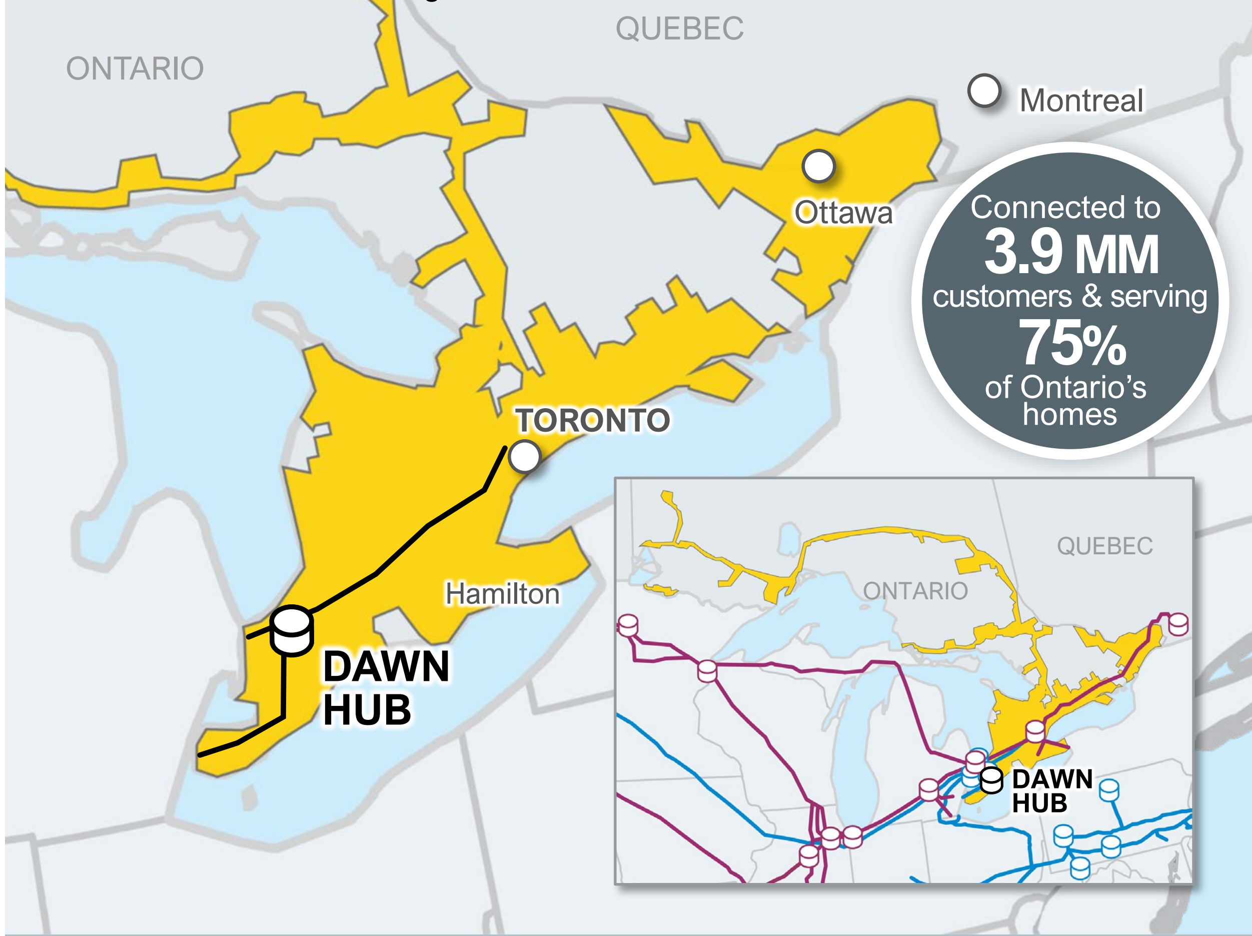
- Largest integrated natural gas utility in N.A.[1]
- One of the largest interconnected storage hubs in N.A.

Stable & Visible Growth

- Generating premium returns and EBITDA growth through incentive rates
- $1B+/yr in utility capital expenditures

Leading the Energy Transition

- Delivering energy efficiency and conservation programs
- Developing innovative lower-carbon solutions
- Investing in RNG[2] & H_2 and exploring CCS[3]

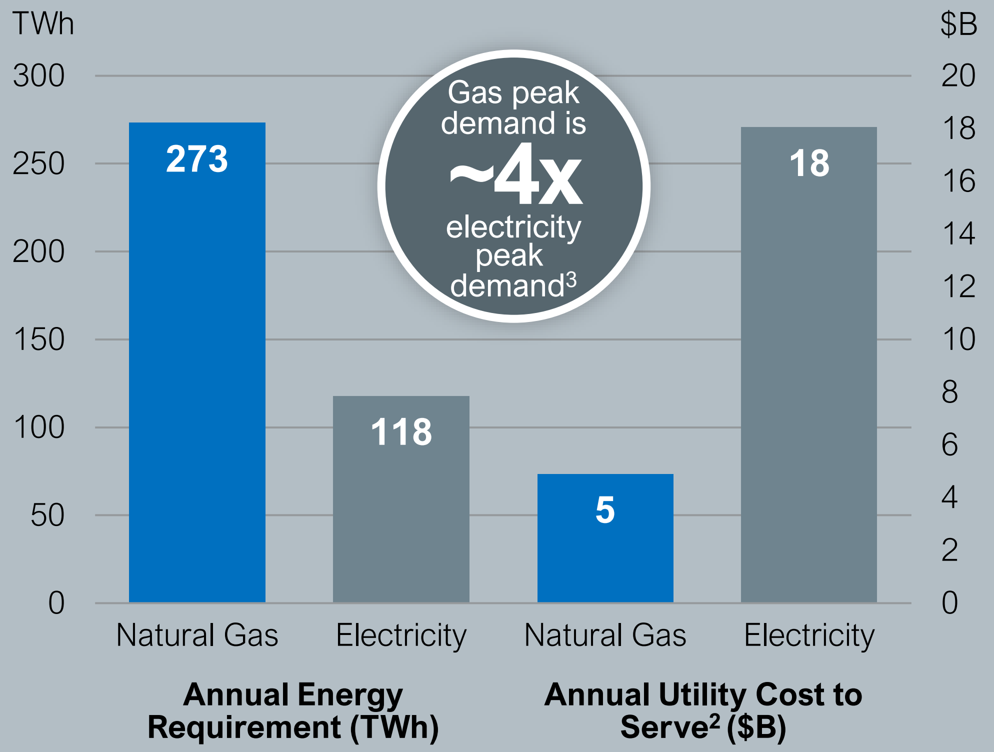


Providing cost-effective, reliable & sustainable energy to Ontario

(1) Based on volumes (2) Renewable Natural Gas (3) Carbon Capture & Storage

Natural Gas is Critical to Enabling Growth

Ontario's Energy Landscape[1]



Population Growth in Ontario

- Anticipated growth of 2.2 million people over the next 10 years
- Natural gas critical to resiliency and meeting heating requirements

Economic Growth

- Industrial demand has few economic alternatives
- Up to 1.5 GW of new natural gas generation needed[4]

Sustainable & Cost-Effective

- Deploying and piloting lower-carbon technologies
- Diversified approach to net-zero is less expensive and more reliable

Strong fundamentals support continued connectivity to natural gas in Ontario for decades

(1) Ontario Energy Board 2021 Yearbooks for Electricity and Natural Gas Distributors (2) The annual electricity cost to serve does not include the $3.1 B Renewable Cost Shift subsidy (3) Winter peak
(4) Executive Council of Ontario, Order in Council 1348/2022

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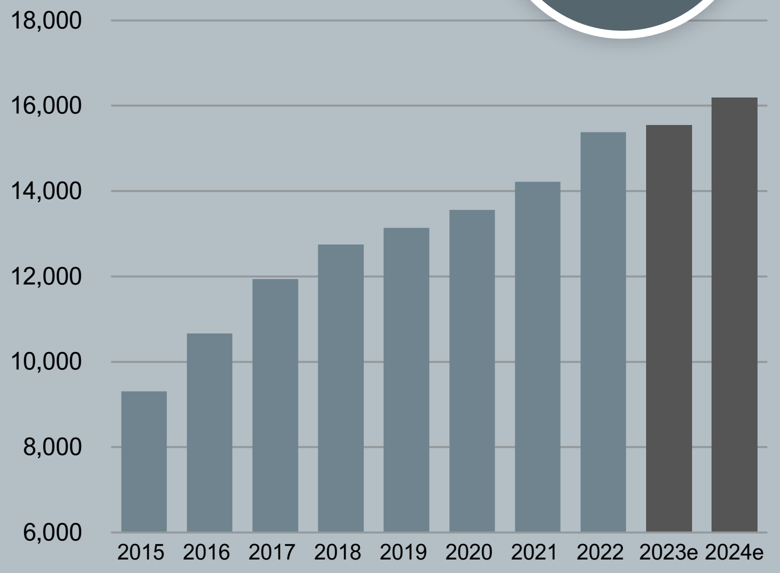
Demonstrated Benefits of Regulatory Framework

Rate Base

(MMs)

Predictable rate base growth



$1B+ of annual capital spend

Investor Benefits

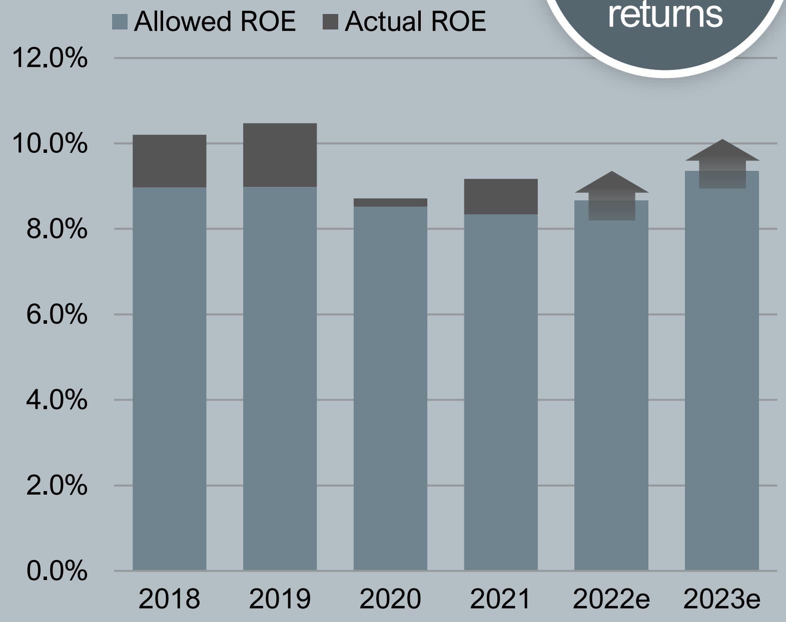
- ✓ Consistent and transparent rate making process
- ✓ Generates traditional and lower-carbon rate base growth
- ✓ Incented to identify and implement cost saving measures

Customer Benefits

- ✓ Delivering $121MM of efficiencies[1]; O&M savings of ~12%
- ✓ Safe, reliable and cost-effective system
- ✓ Maintaining affordability

Realized ROEs

Consistently achieving allowed returns



Incentive framework – a win-win solution

Building on a strong track record of attractive returns

(1) 2024e

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Extending a Mutually Beneficial Incentive Model

2024-2028 Regulatory Framework

- Effective Jan. 1, 2024 with rate certainty to 2028
- Identify and implement efficiencies
- Growing earnings driving attractive ROEs
- Demonstrates the case for rate base growth
- Supports investment in the energy transition
- Incorporates RNG into gas supply plan

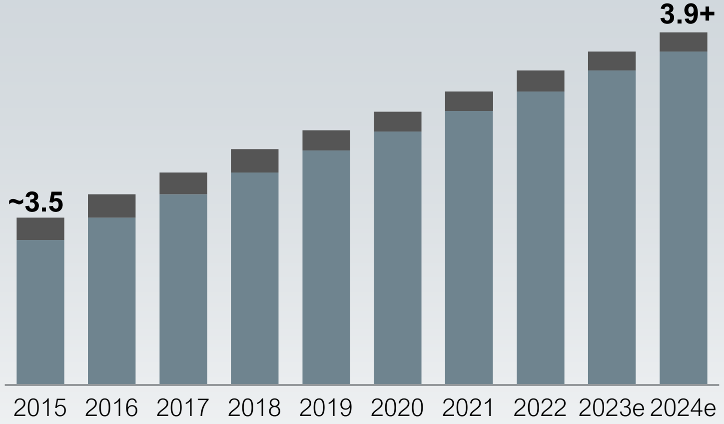
Summary of OEB Application

Term	5 years: 2024 cost of service & 2025 – 2028 incentive period
Inflation Protection	Inflation + 1.35% productivity factor
Earnings Sharing	50:50 sharing of earnings above 150 bps over OEB allowed ROE
Capital Plan	$1B+ per year
Equity Thickness	Proposed increase up to 42% by 2028
Amalgamation Benefits	Streamlining rates, services and processes

Incentive rate structure extends framework to grow earnings

Multiple Platforms for Predictable Utility Growth

Customer Connections

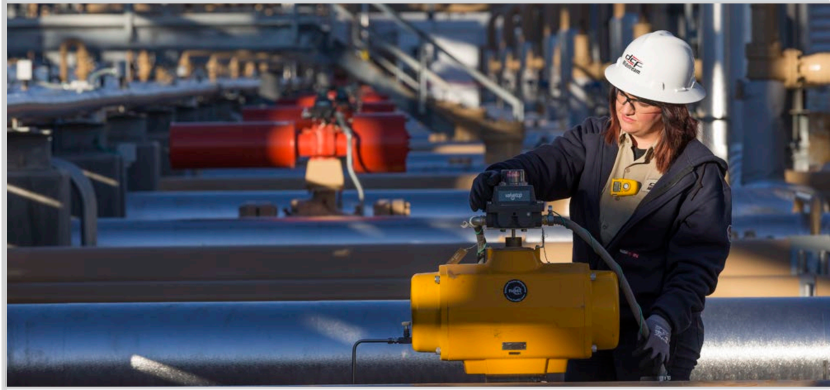


- Customer adds of >45k in 2022
- Remains first-choice for heating[1]
- 4 new community expansion projects planned for 2023

Power Generation

- Natural gas is critical to Ontario's power sector
- Natural gas enhances electricity system reliability
- Up to 1.5 GW of new generation[2]

Industrial Growth



- Growing demand from greenhouses & manufacturing
- Supports industrial GHG emission reductions
- Underpinned by Dawn Hub reliability

Increasing access to natural gas enables Ontario's economic growth

(1) Enbridge internal data (2) Executive Council of Ontario, Order in Council 1348/2022

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Storage, Transmission & Distribution Growth

Hamilton Growth Project

Reduces GHG annual emissions by **3MMtCO$_2$e**


THE HAMILTON SPECTATOR Feb 2, 2023

Dofasco needs 14-kilometre natural gas pipeline built for 'green steel' project

ArcelorMittal Dofasco says its plan to transition to "green steel" by 2028 hinges on the construction of a 14-kilometre natural gas pipeline in Hamilton.

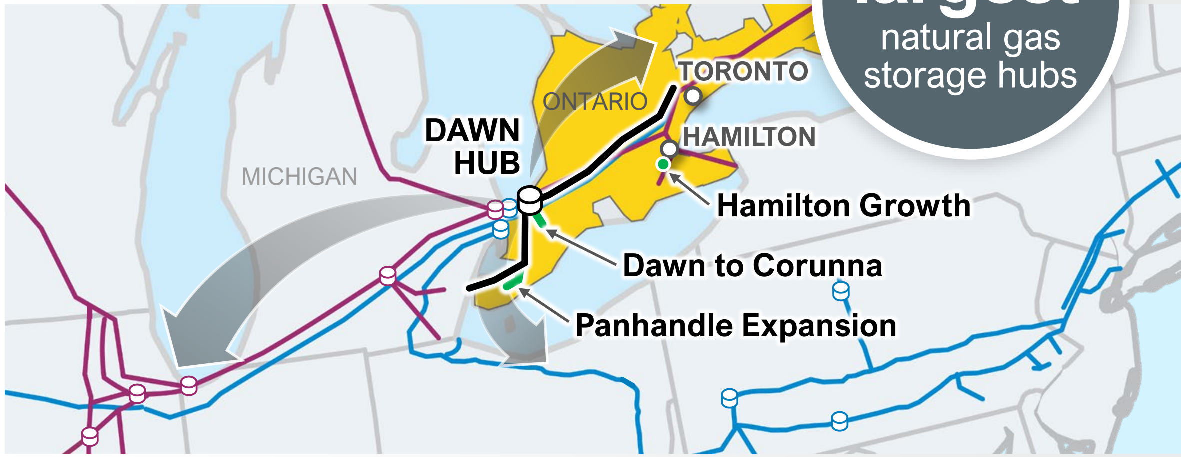
The phasing out of coke ovens and blast furnaces in favour of electric arc furnaces will eliminate three million tonnes of carbon dioxide, says Tony Valeri, vice-president of corporate affairs.

The $1.8-billion project is expected to double demand for natural gas from roughly 500 million cubic metres to more than a billion, Valeri told council Wednesday.

- Supporting Dofasco's transition to a lower carbon footprint
- Modifying steel making process to shift from coal to gas
- Largest GHG reduction project underway in Ontario
- Project achieves a 60% reduction in GHG emissions

Dawn Hub Supports Growth

One of N.A.'s **largest** natural gas storage hubs



- Connects supply basins with strategic N.A. markets
- Liquid trading hub; 100+ energy marketers active at Dawn
- 288 Bcf storage capacity with reliable & proven takeaway
- $700MM on storage, transmission & distribution projects

Supporting our customer's energy needs while lowering emissions

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Growing Lower-Carbon Opportunities

Energy Efficiency

- Conservation is a cornerstone
- Selected to deliver NRCan's[1] Greener Homes program
- Annual funding of $330MM for energy efficiency and conservation programming

Integrated Gas System

- Published first of its kind study: "Pathways to Net-Zero" for Ontario
- Electric and gas system integration
- Lowest-cost option to achieve net-zero includes hybrid heating
- Gas system longevity & growth under any scenario

"Green" Gas & CCS

- N.A.'s 1st H_2 blending facility
- Transporting 1.3 MMcf/d of RNG[2]
- 4 RNG projects in construction
- 20+ RNG projects in development
- 700+ $MMtCO_2$ sequestration potential[3]

Enabling the energy transition with More Gas, Less Gas, Integrated Gas & Green Gas

(1) Natural Resources Canada (2) This represents 4 projects in service (3) Geological Sequestration of Carbon Dioxide: A Technology Review and Analysis of Opportunities in Ontario, 2007

Lower-Carbon Project Spotlight

$600MM+ investment opportunities through 2025

Gatineau Hydrogen

- Up to 15% H_2 for ~44,000 customers[1]
- 15 km pipeline & injection facility
- 15,000 tCO_2e of annual emission reductions
- ISD 2026

Incubating lower-carbon technologies

Dufferin RNG

- Partnered with City of Toronto to produce RNG from green bin waste
- Converting 55,000 tonnes of organic waste into RNG eliminating more than 9,000 tCO_2e annually

Lower-carbon growth with utility-like returns

Extending the life of our assets

(1) By volume

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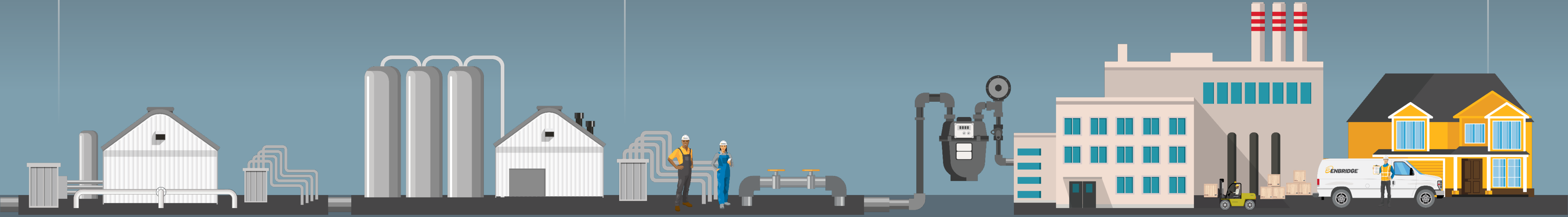
Emissions Reductions

Scope 1: Equipment Improvement
Savings[1]: **13,900 tCO_2e/yr.**

Scope 1: Blowdown Recovery
Savings[1]: **8,000 tCO_2e/yr.**

Scope 1: Fugitive Emissions
Savings[1]: **8,200 tCO_2e/yr.**

Scope 3: Energy Efficiency Lifetime Savings[2]:
58 $MMtCO_2e$



Compressor Station

Compressor Station with Dehydration

Commercial, Industrial & Residential Customers

Successfully reducing emissions throughout the value chain

(1) Emissions savings represent estimated emission reductions once opportunity is fully implemented (2) These results are based on measures that customers implemented between 1995 and 2021 and their associated lifetime savings. Results for measures implemented in 2021 have been audited by a third-party auditor; however, they remain subject to OEB approval.

First-choice investment opportunity driven by:

Extending successful incentive rate making model providing stable earnings growth

Rate base growth through 2028 and beyond

Ensuring energy security and reliability

Leading the adoption of lower-carbon technology

$1B+

annual capital spend

ENBRIDGE GAS INC.

Answer to Interrogatory from
AnnaMaria Valastro (Valastro)

Interrogatory

Question(s):

The Ontario Energy Board is an oversight agency mandated to oversee energy rates to consumers because Enbridge is not a public utility. It is a for profit business and a monopoly.

Therefore, I am asking the OEB:

- to review whether rate hikes for natural gas are necessary for 2024 and 2025;
- what are the impacts of rate hikes to consumers in this period of inflation 2024 and 2025;
- Is Doug Ford's plan to increase gas fired plants in Ontario to produce electricity and heating – over renewables – costing rate payers more money;
- Would a more diverse energy supply (wind, solar, water) remove or reduce the need for rate hikes by Enbridge.

Response:

As the items in Ms. Valastro's email were submitted at the same time as other interrogatories, Enbridge Gas is providing its high-level comments as an interrogatory response.

Enbridge Gas notes the proposed rates in this Application will support a system that can continue to meet customers' needs safely and reliably in a cost-effective way, while at the same time helping them prudently prepare for the energy transition that is underway in the communities where they live, driven by existing and planned federal and provincial policies.

Natural gas continues to be the most cost-effective energy solution for homes and business, and costs significantly less than heating your home or business with electricity, oil or propane.

Enbridge Gas is excited and confident about the role the Company can play in supporting customers, the province, and municipalities in achieving their greenhouse gas (GHG) emission reduction goals.

Large-scale multi-decade transitions such as this need to be done in a way that is orderly and not disruptive. An orderly transition is one that allows energy consumers to adapt to energy transition such that Ontario's energy systems provide cost-effective choices that are reliable, resilient and secure. The Pathways to Net Zero report provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2 shows that using both the gas and electric systems to achieve GHG reductions is a lower cost than electrification alone.

Enbridge Gas rates pay for natural gas supply and delivery. Electricity supply costs are not recovered by Enbridge Gas. The Independent Electricity System Operator (IESO) is responsible for planning and securing electricity needs for the Province based on reliability, sustainability and affordability.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T3/S1/Attachment 2

Question(s):

Please provide a copies of the following documents:

a) An organization chart for Enbridge Gas Distribution prior to the merger;

b) An organization chart for Union Gas Limited prior to the merger;

c) A complete list of all roles that were eliminated.

Response:

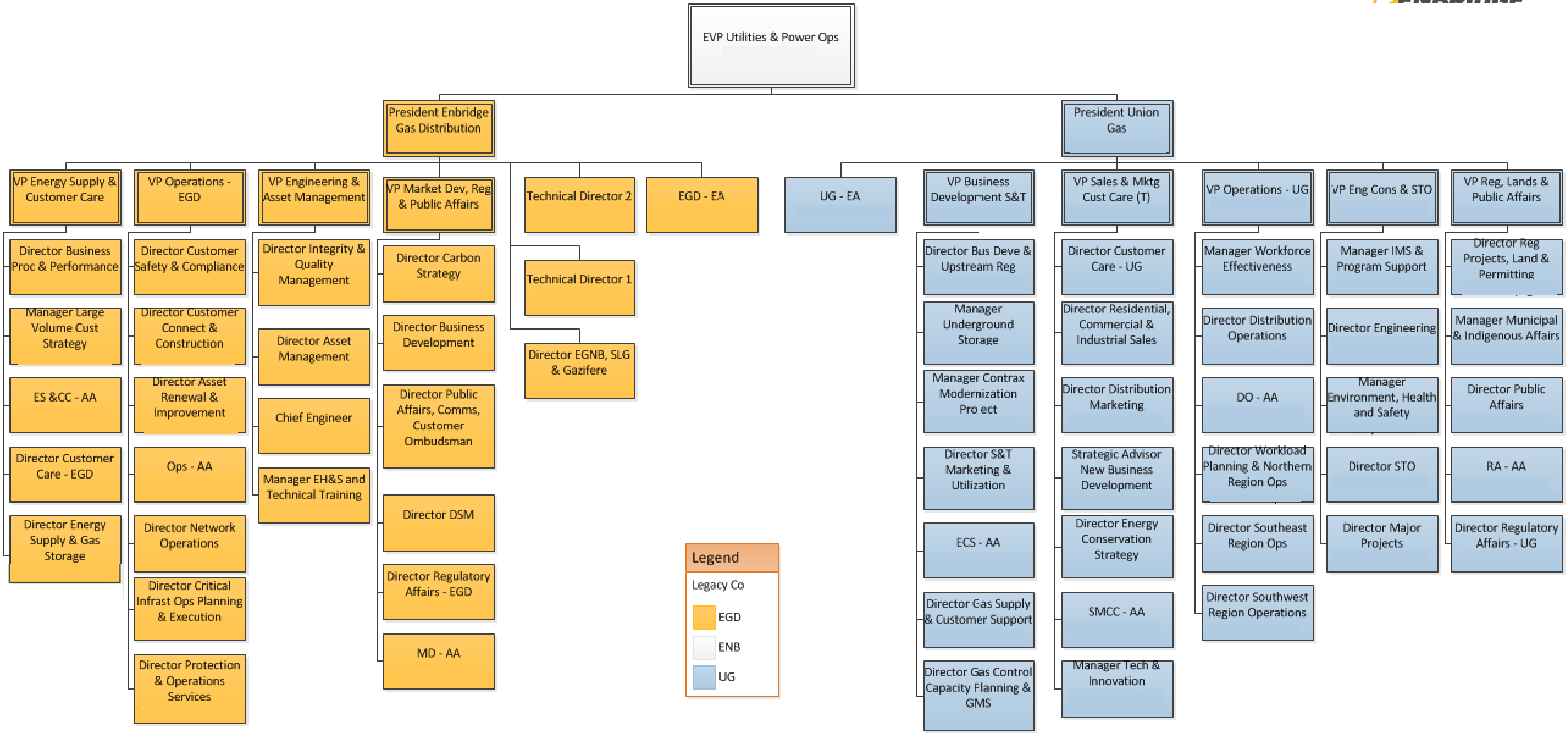
a-b) Please see Attachment 1 – EGD & Union Organization Structures Prior to Amalgamation.

c) Enbridge Gas assumes this request is for all roles that were eliminated as a result of the amalgamation which occurred January 1, 2019. There were 200 roles eliminated as a result of the amalgamation and an additional 241 eliminated via the Voluntary Workforce Options (VWO) program for a total of 441. To protect confidentiality of employees whose roles were eliminated, Enbridge Gas will not provide a detailed list of all roles. However, in Table 1 the Company provides a summary of roles eliminated by area, mapped to the amalgamated organizational structure.

Table 1
Summary of Roles Eliminated by Area

Line No.	Area	# roles
1	Business Development & Regulatory	45
2	Customer Care	60
3	Distribution Operations	73
4	Energy Services	16
5	Engineering & STO	228
6	Central Functions	11
7	Other	8
8	Total	441

EGD and Union Organization Structures Prior to Amalgamation



ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Section 19.1 [Exhibit 1, Tab 3, Schedule 1] provides a consolidated list of the approvals Enbridge is requesting. The list includes specific documents.

Question(s):

Please confirm that Enbridge is not seeking OEB approval of any other Enbridge documents (e.g. policies, manuals, plans, etc) not on the list in Section 19.1. If incorrect, please provide the full list.

Response:

Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-3-1, Attach 3

Question(s):

Please explain in detail how Enbridge plans to change its board of directors and governance practices over the rebasing term to reflect the changing public expectations arising out of the energy transition. Please provide all studies, memoranda, presentations and other documents related to governance and the energy transition

Response:

Enbridge Gas Board of Directors includes Michele Harradence, President, James Sanders, SVP Operations and Bill Yardley who replaced George Unruh in 2023. Energy transition governance is provided both by the Enbridge Gas and the Enbridge Inc. Board of Directors.

Enbridge Inc. and Enbridge Gas are always seeking to ensure that their Board of Directors have the right skills and experience to guide the Company through its energy transition. Board composition is assessed regularly, to ensure Board members are well equipped to understand and oversee ESG matters, including climate change and the energy transition. Enbridge Inc. discloses a skills matrix each year. Currently, most Enbridge Inc. directors indicate that they have experience with policy, regulations, operations, transactions relating to renewable energy sources, new energy technologies, and climate change. All directors indicate that they have an understanding of ESG, corporate social responsibility and sustainability practices and their relevance to corporate success. With respect to directors with operational energy transition experience, Jason Few is the President & CEO of FuelCell Energy, Inc., a global leader in manufacturing stationary fuel cell energy platforms for decarbonizing power and producing hydrogen.

Energy transition governance at the Enbridge Inc. Board of Directors is largely exercised through the Sustainability Committee and the Safety and Reliability Committee. The former oversees Enbridge Gas's GHG emissions goals and targets, Indigenous and stakeholder engagement, human rights and ESG reporting. This includes overseeing progress on our ESG goals. The Safety and Reliability Committee oversees safety and operational risks, including physical and transition climate-related risks, cyber security programs and elements of our safety culture. At each Board meeting, the Board receives updates and provides feedback on progress towards our goals and execution of our strategy. This critical feedback ensures that we are continuously refining and improving our approach.

Management provides quarterly updates to the Enbridge Gas Board of Directors on safety, operations, customer care, regulatory and business development on a quarterly basis. Please see response at Exhibit I.1.2-CCC-1, Attachment 1 (presented to Enbridge Gas Board of Directors and Enbridge's Board of Directors) and Attachment 2 (presented to Enbridge's Board of Directors) for material provided to the Enbridge Gas and Enbridge Inc. Boards of Directors on the Company's rebasing application.

Enbridge Gas management provides governance on energy transition matters though the Energy Transition Steering Committee. Please see attached presentations describing how the management governance of energy transition is structured (Attachments 1 through 4).

Energy Transition Governance

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Energy Transition Planning Team

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Director, Energy Transition Planning
Cara-Lynne Wade

Manager, Carbon Strategy
Peter Mussio (3 reports)

Manager, Integrated Resource Planning
Chris Ripley (4 reports)

Manager, Carbon & Energy Transition Planning
Jennifer Murphy (5 reports)

ET Governance Model

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EI Emissions Reduction SteerCo

Chair: EI ESG & Public Policy
Members: EI SVP/EVP and BU VP (GDS: MG, CLW, PM)

EI Emissions Reduction Working Group

Chair: EI ESG & Public Policy
Members: Director Leads for EI and per BU (GDS: CLW, Peter)

ET Advisory Group

Chair: Cara-Lynne Wade, Members: Keith Boulton, Mark Kitchen, Sarah Van Der Paelt , Scott Dodd, Tracey Teed-Martin, Neil MacNeil, Ian Macpherson, Colin Healey, Andrea Seguin, Hilary Thompson, Jason Gillett, Clancy O'Hara, Bike Balkanci, Jean-Benoit Trahan, Patricia Squires, Jennifer Burnham, Katie Hooper, Wes Armstrong

ET Leadership Group

Chair: Jennifer Murphy
PM: Ayman Salama
Members: leads from below workstreams

RNG / H2 / CCUS sub-working group under development

Scope 1&2 sub-working group

Hydrogen TBD	**RNG** Nicole B.	**CCUS** Jeff C.	**IRP** Chris R.	**CNG/LNG** Steve K.	**DSM** Craig F.	**Other Low Carbon** Ravi S. / Sutha	**Product Development** Rob Kennedy	**Climate/ NZ building policy** Heidi S.L./ Jenn M.	**Scope 1 &2** Peter M.

Supporting Groups: Regulatory/Rebasing (Pat S.), Legal, GR (Trevor E.), Finance (Elena C.), PA (Andrea S.), Municipal ET Plan (Cindy M.)

Scope 3 Working Groups

under development

Scope 3 Working Group Governance

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Chair: Jennifer M.
PM: Ayman Salama

RNG / H2 / CCUS sub-working group under development

RNG
Nicole B.

Hydrogen
TBD

CCUS
Jeff C.

DRAFT
Lead: Nicole B.
Members:
Project Mgmt: TBD / /Ayman?
Gas Supply: Nicole Brunner
BD Voluntary: Nicole B
BD Producers: Steve R/ Gord
ET Planning: Jenn/Cora
Operations: Gonzalo Juarez
Engineering: ?
Billing Systems Rep/TIS (extended but welcome early)
Enfranchise Sales General Service Sales Rep (Wayne P.- what do customers want and how to help them get RNG)
AMP: Bob W

DRAFT
Lead: TBD
Members:
Project Mgmt: TBD /Ayman?
Gas Supply: Nicole Brunner
BD: Sam McDermott
BD: Steve Kay
ET Planning: Jenn /Cora,
Engineering: Dayana , Kara
Transmission Planning: Gord Dillon / Melissa D.?
Operations: Gonzalo Juarez
Distribution Optimization Engineering (DOE): Brad Clarke
S&T – BD: Jeff Cadotte, Matt Thomas
AMP: Bob W

DRAFT
Lead: Jeff C
Members:
Wayne P.
Matt T

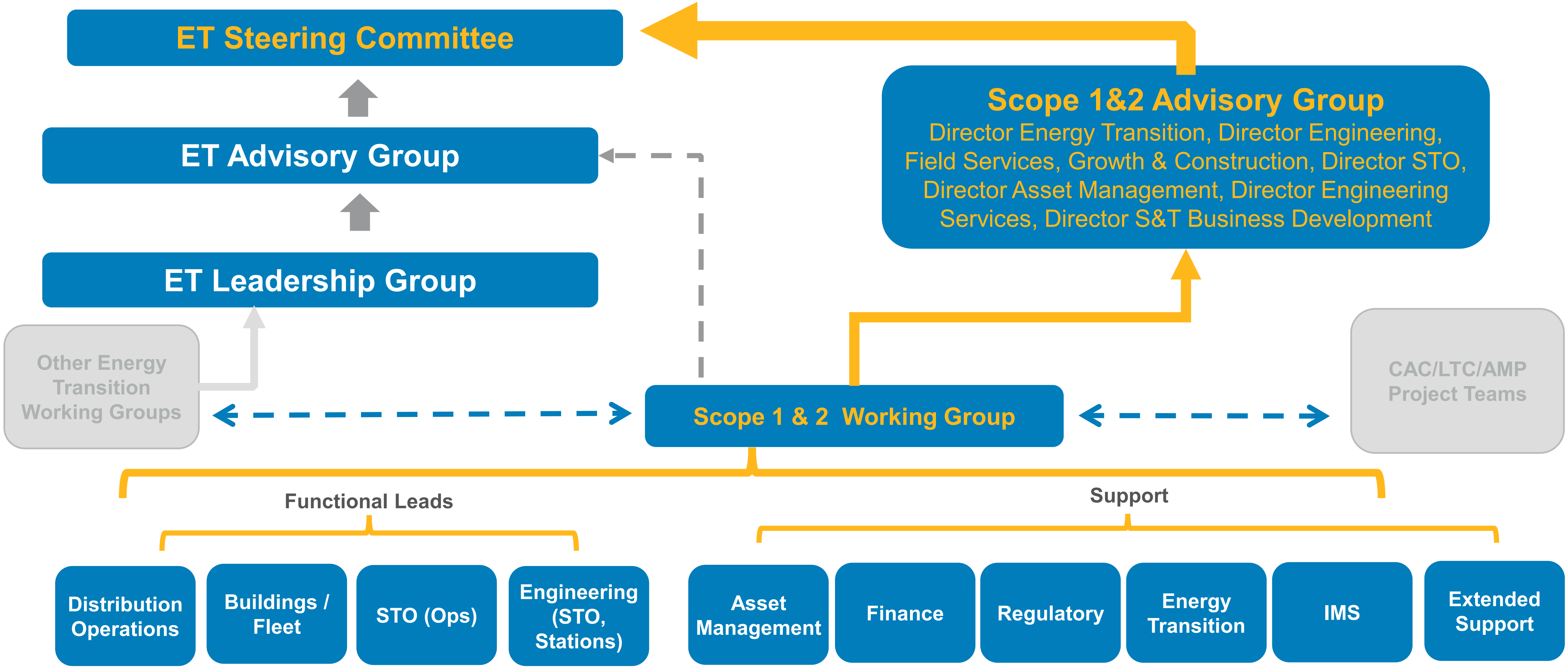
Extended Support Team:

Bradley Latanza, Andrea, Priyanka, Asset Management: Catherine, Regulatory: Pat Squires; Marketing: Priyanka Gupta, ; Public Affairs/Advocacy: Andrea Stass ; Billing Systems Rep/TIS (name TBD), ; GR: Brad Lattanzi ; Scope 1 & Scope 2 Emission lead: Peter Mussio ; Transmission Planning (or is this just needed for Hydrogen?):

Scope 1&2

Program Governance and Working Groups

Scope 1 & 2 Working Group: Governance Model



Scope 1&2 GHG Reduction Working Group Governance

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Scope 1&2 Working Group

Chair: Peter Mussio
Program Manager: Luna Munro/Ayman Salama

Functional Leads

- Distribution Operations: Roddi Basserman
- Buildings/Fleet: Gonzalo Juarez
- STO (Ops): Chris Stubberfield
- Engineering: STO: Jeff Falkiner, Stations: Carrie Cook

Support

- Asset Management: Mike Kreitner, Candice Case
- Finance: Rich Szymanski
- Regulatory: Adam Stiers
- Energy Transition: Ainslie Murdock
- IMS: Sam Tyrell

Extended Support

- Environment: Doug Schmidt, Sarah Kingdon-Benson*
- RNG: Nicole Brunner*
- Hydrogen: Sam McDermott*
- CCUS: Jeff Cadotte*
- New Commercial Technologies: Ravi Sigurdson*
- Energy Services: Matt Thomas*
- Measurement and Telemetry: Dayana Musa*
- Integrity Management: Angela Scott*
- Indigenous Relations: Lauren Whitwham*
- Engineering Construction: Dan Wallace*

* To Be Confirmed

Energy Transition Governance Overview

—

Steering Committee

February 16, 2021

Fiona Oliver-Glasford

Manager, Energy Transition Planning

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Energy Transition Governance

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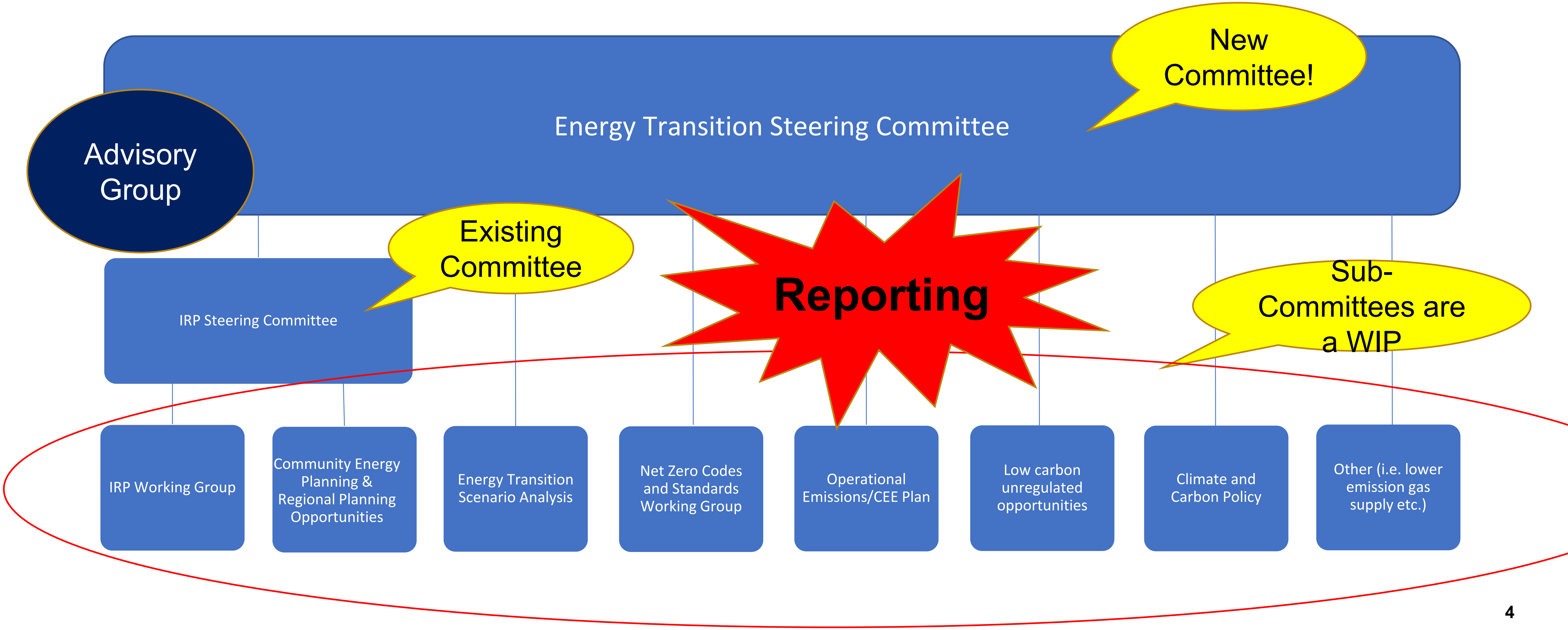
- Growing recognition that investors are interested in our planning related to climate risks, climate risks influencing investment decisions
- Policy makers at all levels of government developing new climate policies
  - Federal: various policies under Pan-Canadian Framework, Net-Zero Carbon by 2050 target
  - Municipal: Community Energy Plans, climate emergencies
- Key part of the long-term strategic planning for our Utility given signals and pressure the OEB and intervenor groups
- Increased focus on climate risk/policies at corporate level (Enbridge Inc.)
  - Setting targets for GHG reductions from each BU linked to performance management
  - Increased external climate disclosures – Climate Report, Corporate Sustainability Report
  - Scenario planning to determine impact on the business of climate policy
  - Set new strategic target “Adapting to our Energy Transition”

Energy Transition Governance

- Clarity of our Energy Transition Strategy so that we are taking direction but also informing EI’s planning.
- Alignment between the various cross functional areas so as to best optimize solutions and opportunities
- Ensure fulsome reporting on activities is being captured and summarized for senior level insight and for communication against the GHG scorecard.
- Will ensure the right organizational structures Numerous people, processes around the Company will feed into this structure
- Create dynamic and aligned vision on Energy Transition that will engage employees!

Energy Transition Governance



Energy Transition Steering Committee

- Proposed standard report with key area updates from Sub-Committees
- Meetings to have Standing Agenda Items (proposed):
  - EGI GHG Scorecard/Target Status
  - Energy Transition Scenario Analysis
  - Other? General Discussion on gaps/wins/challenges.
- Feature Discussions each meeting could include:
  - Offsets
  - Hydrogen or RNG
  - Codes and Standards/Net Zero Buildings
  - Low Carbon Solutions
  - Climate Policy (including CFS for the liquid stream, methane etc.)
  - Provincial Energy Planning
  - Municipal planning and related activities

Information or Capacity Gaps?

- Project Manager/Administrator to support reporting related to all of the Energy Transition elements
- Other?
  - New Sub-committee areas to be formed or formalized?

Thank you

- Brief meetings will be held with the Energy Transition Advisory Group prior to the Energy Transition Steering Committee to discuss the agenda for the Steering Committee and inform direction of the discussion.

Energy Transition Steering Committee

April 2021 Agenda

1. Safety Moment - Peter Mussio
2. GHG Emission Reduction Metrics Scorecard Update – Peter Mussio and Malini Giridhar
3. Energy Transition Scenario Analysis Update - Cora Carriveau
4. Energy Transition Governance Discussion – Cara-Lynne Wade and Jennifer Murphy
5. Q/A

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GHG Emission Reduction Metrics Scorecard

Peter Mussio and Malini Giridhar

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Monday, March 29

ENG Project – *Facility GHG Emission Reduction (Cross Functional)*

For the Period April 1 to May 1, 2021 Overall Project Status: Green Author: Luna Ghose Munro

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Project Overview: Initiated to support Enbridge's GHG emission reduction targets and to meet the GDS 2021 scorecard objectives. Project will identify and review potential opportunities and strategies to achieve cost-effective GHG reductions driven by the Asset Management Plan, updated operating practices, equipment modernization/innovation, and emerging policy/regulations. Includes 1.a) Develop 3-year GHG reduction plan, b) track and report GHG emission reduction through dashboard, 2. Implement 3 EGI emission reduction initiatives, 3. Enterprise wide GHG intensity reduction target.

Project Approach and Overall Time Horizon: 1. a) Review GHG Opportunities already identified through previous GHG projects + AMP with Functional Leads and SMEs, complete detailed assessments to feed into 3-Year Emission Reduction Strategy. b) PM to provide information to BU Dashboard managed by Corporate Emission Working Team, 2. Initiative Owners to report on progress, environmental support to complete GHG reduction calculations 3. Enterprise wide GHG intensity reduction to be completed by Corporate Sustainability and Strategy and Power, PM to provide updates on projects as required. Overall timeline is end of 2021, with specific targets and incentives to accelerate completion as per scorecard.

Accomplishments this period:

- Project charter approved
- Established Emissions Reduction Working Group (ERWG) (GDS)
- Reviewed governance structure requirements (ENG Integration, GDS Scorecard Metrics)
- Project approved and given cross-functional status
- Established Corporate Emissions Working Team under Emissions SteerCo (Enbridge Inc.)

1.a) 3-Year Plan – Established working group.
2.a) Leak Backlog – Developed 3-year plan, implemented reporting and tracking process.
2.c) High Bleed Pneumatics – Inventory of pneumatic devices complete, 2-year budget developed.

Pending Decisions or Leadership Direction Required:

- Financial Analysis Template for Detailed Assessments TBD with Corporate Emission Steering Committee, Template will also be used for Opportunity Ranking
- BU Dashboard from Corporate Emission Steering Committee

Obstacles (O)/Dependencies (D):

D- Corporate Emission Steering Committee Direction on BU Emissions Dashboard.
D- Corporate approach to meeting Corporate target could alter BU 3-Year GHG reduction plan.
D- Corporate Sustainability/Strategy is responsible for 3. Enterprise wide GHG Intensity Reduction target.
D- AMP Project Decisions.
D- Other Environmental regulatory dependencies (OBPS, MSAPR, Methane Reg, etc.).

Project Risks and Treatment:

- Insufficient Internal Resourcing – Steering Subcommittee Support
- Detailed Assessments not completed or updated – Regular Communication with Function Leads
- Reduction Measures not resulting in estimated reduction – Corporate Offset Strategy
- AMP Project Reevaluation – Regular Communication with AMP Functional Lead

What's Next to Tackle:

1.a) Kick-off meetings, review long term AMP (ID all projects with GHG impacts)
1.a) Finalize Corporate Prioritization Criteria (Internal Carbon Price and Investment Review Criteria)
1.b) BU Dashboard development with Corporate Emission Working Team

Resourcing Update:

- PM assigned to Project
- Functional Leads identified, for 3-Year plan and 3 EGI ER Initiatives
- Additional SMEs to be identified for opportunity review and completion of detailed assessments

Next Planned Communication or other Change Management Event:

- Kick off meetings with Functional Leads, targeted discussions with SMEs.

Key Deliverable / Milestones (happening in < 12 months)	Target Date	Revised Date	Progress / Status
Develop Strategy for 3 EGI Emission Reduction Initiatives	June 15th		50%
Identify and Prioritize Opportunities for Assessment	May 31st		25%
Develop Long Term Modernization Plan	July 31st		25%
Develop BU Dashboard Reporting Process	Aug 31st		0%
Complete Detailed Assessments	Oct 31st		0%
Approve 3-Year Emission Reduction Strategy	Oct 31st		0%

STATUS LEGEND						
	G	Ongoing / On Track	Y	Off Plan and Recoverable / Requires Focus	R	At Risk / For Discussion with Leadership

Energy Transition Scenario Analysis Update

Cora Carriveau

Friday, April 23

Project Status

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WP1: Reference Case & Critical Drivers

- **COMPLETED**
- Data discovery with internal stakeholders
- Defined 15 Critical Drivers relevant to model
- Delivered Reference Case Model Outputs

WP2: Parametric Analysis

- **COMPLETED**
- Identified relative impact of Critical Drivers
- Created Data Visualization Platform (Power BI)

- **COMPLETED**
- Internal and Externa stakeholder engagement
- Defined scenarios
- Defined scenario assumptions

WP4: Scenario Modelling

- **IN PROGRESS**
- Modelling of Scenarios
- Output files and Project Report
- End of May delivery

- Hosted two engagement sessions with participation from 15 internal SMEs
  - DSM, Gas Supply, BD, Technology and Innovation, Municipal, Regulatory, Forecasting
  - Presented supply and demand related assumptions for each scenario, and collected feedback via follow-up survey
- Hosted one engagement session with participation from 17 external stakeholders, received feedback via survey from 6 participants
  - Stakeholder group (Toronto District 2030) comprised of IESO, Canadian Green Building Council, housing developers, Enwave, academics, YMCA
  - Comments during session were generally supportive of the ETSA work, but encouraged us to complete decarbonization planning, with goal of absolute zero emissions by 2050, not net-zero
- Based on feedback received, identified specific industrial end-uses where fuel switching to electricity or hydrogen could easily occur.

Energy Transition Scenario Analysis

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	Steady Progress	Diversified Pathway	Electric Pathway
Achieves net-zero by 2050	• Not likely	• Targeting	• Targeting
Carbon price by 2038	• \$200/tCO_2 (\$170/tCO_2 by 2030, escalated by inflation)	• \$200/tCO_2 (\$170/tCO_2 by 2030, escalated by inflation)	• \$338/tCO_2
Codes & Standards	• Net-zero energy ready by 2038 • Retrofit code implemented by 2035	• Net-zero energy ready by 2035 • Retrofit code implemented by 2030	• Net-zero energy ready by 2035 • Retrofit code implemented by 2030
Fuel switching policy	• None	• Some communities ban gas for new construction • Incentives encourage existing homes to fuel switch	• Province-wide mandate to switch to electric heating starting in 2025 for new construction and existing homes. • Some industrial electrification
RNG	• Modest, <10% of gas supply	• Maximized,15-25% of gas supply	• Modest, <10% of gas supply
Hydrogen	• Modest, < 5% of gas supply	• 100% H2 networks introduced in 2030 • Blending 10% H2 in natural gas system	• Minimal, < 1% of gas supply
CCS	• Minimal, capture mainly at refineries, H2 generation	• Maximized, capture at most large emitting industries	• Minimal, capture mainly at refineries, H2 generation

Energy Transition Governance Discussion

Cara-Lynne Wade and Jennifer Murphy

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Monday, March 29

Energy Transition Planning Committee

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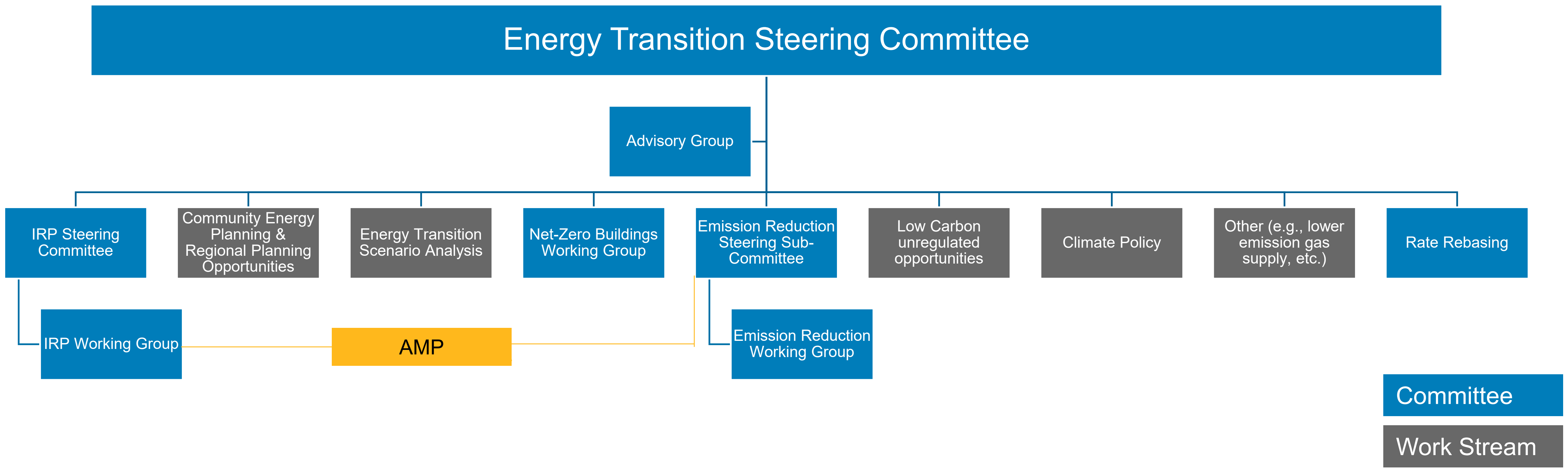
- Oversee and guide long-term energy transition strategies
- Ensure alignment between the various cross functional areas to best optimize solutions and opportunities
- Oversee progress on energy transition activities such as progress against GHG scorecard

Feedback received to-date:

- "What is the scope of the ETSC? Have we adequately captured it?"
- "What decisions are being made by the ETSC?"
- "Is a more macro level view of energy transition at EGI.....needed in order to ensure we are working in a coordinated manner and appropriately prioritizing energy transition?"

Energy Transition Steering Committee



Feedback received to-date:

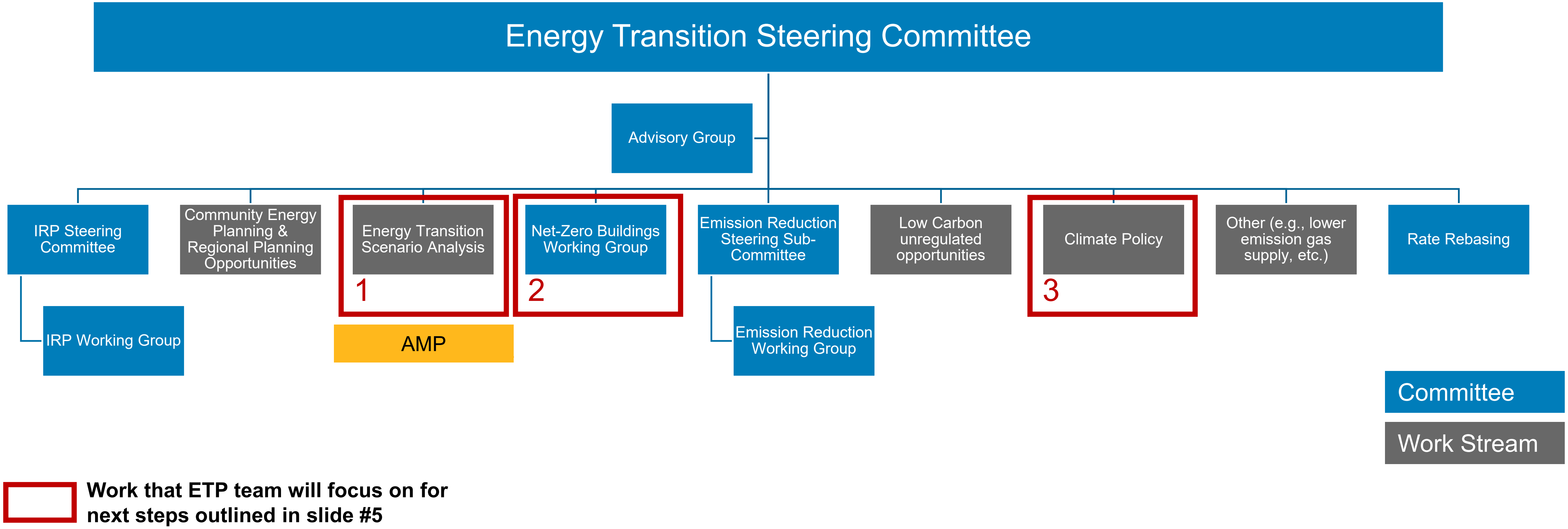
- “What groups / work streams should flow into the ETSC? Are we missing any?”
- “How does the ETSC ensure alignment between the groups / work streams?”
- “Does the ETSC advisory group have the right membership?”
- Do we need to look at “each group having established objectives….in order to ensure we are working in a coordinated manner and appropriately prioritizing energy transition?”

Energy Transition Governance

- Continue to flush out, based on discussions with key stakeholders, the ETSC purpose and governance structure, to ensure that the ETSC is aligned on what:
  - Considered to be in and out of scope for the ETSC; and use this to confirm that the right teams/individuals are engaged.
  - type of decisions/endorsements are currently happening within the sub-committees and work streams, and which of these need to be raised to the ETSC to ensure alignment and prioritization.
  - What type and frequency of energy transition 'information sharing' is required with the ETSC vs ETSC AG, as well as across sub-committees/work streams.

Note: to manage scope of work, the above activity will be conducted on one focus area at a time.

Energy Transition Steering Committee



Q&A

Appendix

Energy Transition Steering Committee

May 28, 2021

Agenda

Agenda Item	Time Allot	Speaker
Welcome & Safety Moment	9:00-9:05	Leanne
GHG Emission Reduction Scorecard Update	9:05-9:25	Peter
Energy Advisory Group – Summary of Discussion	9:25-9:35	Cara-Lynne
Rebasing – Incorporating energy transition into demand forecasting	9:35-9:45	Cara-Lynne
Carbon Policy & NZ Building Update	9:45-9:55	Jennifer & Heidi
Close Out & Confirmation of Takeaways	9:55-10:00	Cara-Lynne

Think before taking that Facebook quiz

Tips to avoid social media scams:

- **Be skeptical**: Before answering a quiz, figure out who created it. Is it a brand you trust?
- **Don't give answers to common security questions**: Be cautious if the questions in a quiz ask for things like your mother's maiden name, street you grew up on, previously owned vehicles, favorite foods, or the name of your high school.

GHG Emission Reduction Project

May 2021 Update

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Peter Mussio

GHG Emission Reduction Project

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AGENDA:

- Corporate Timeline
- Dashboard Update
- Emission Reduction Strategy
  - Deliverables
  - Prioritization Criteria
- Discussion and Next Steps

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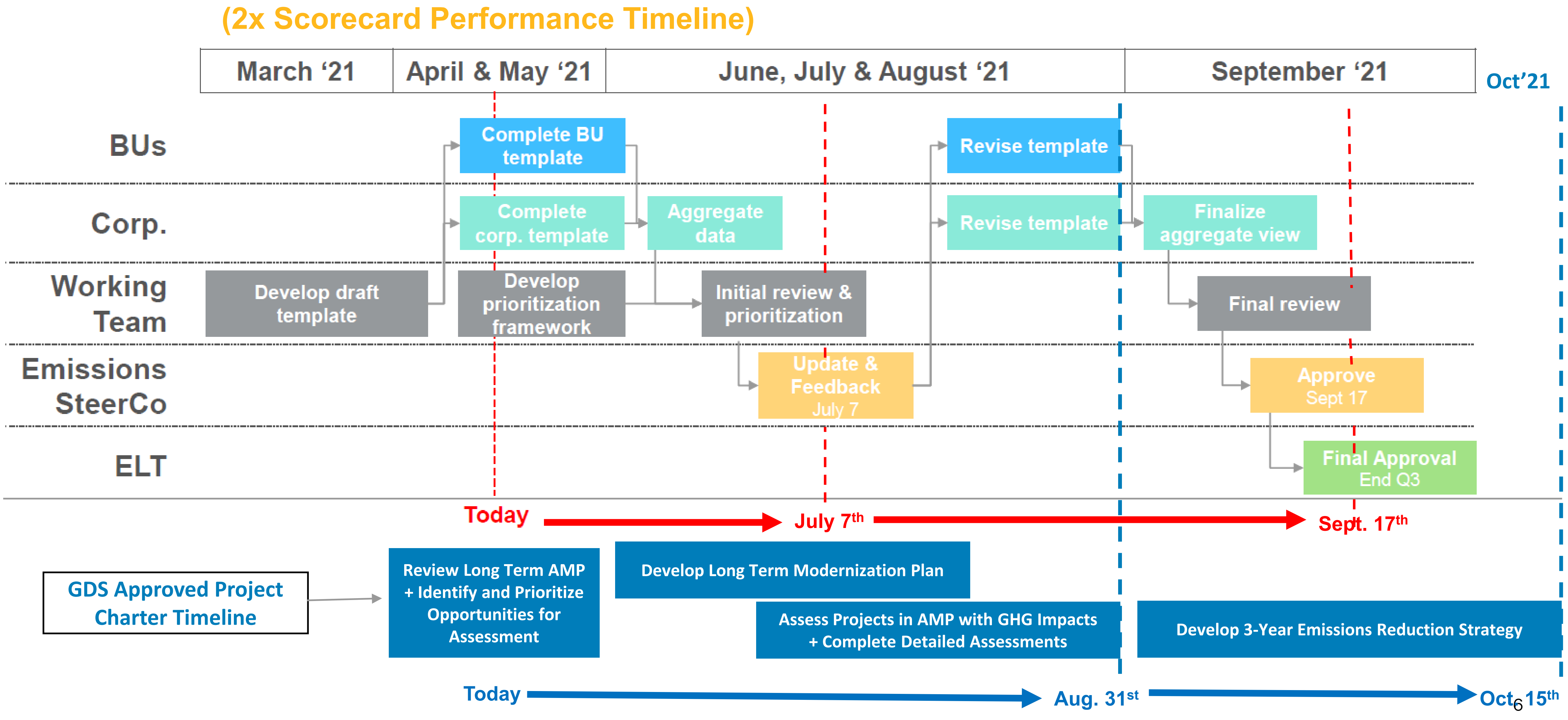
Recall: BU 3+ plan submission & evaluation process



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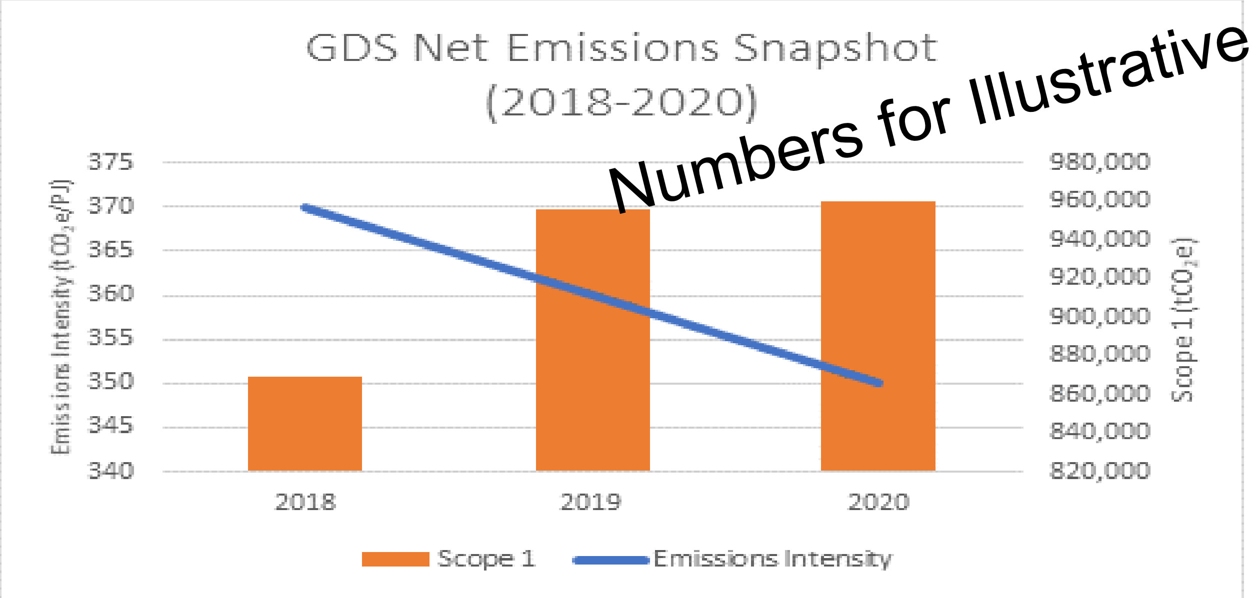
GDS Scorecard Performance Snapshot

Development of 3-Year Strategy*	
Emissions Reduction Initiative Tracker*	
Enterprise-Wide Intensity Relative to 2018 (+/-%) (scorecard target: 0x: 4%; 1x:8%, 2x:12%)	-8%

*Green: >70% on schedule; Yellow: >40% but <70% on schedule; Red: <40% on schedule



Numbers for Illustrative purposes only

GDS 2021 Results Summary**

2021 GDS Emissions Intensity to Date (tCO2e/PJ) (Subset data)	341
Scope 1 Stationary Combustion Emissions (tCO_2e)	**920,000**
Q1:	250,000
Q2:	200,000
Q3	220,000
Q4	250,000
Natural Gas Throughput (PJ)	**2,700**
Q1:	725
Q2:	600
Q3:	650
Q4:	725

**Relative to previous reporting year, Black: no change; Green: reduced; Red: increased

Note: Only report subset data for 2021 due to data availability, plan to incorporate all emissions data when the process is in place.

Proposed: Initiative prioritization framework

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Proposed Prioritization Criteria

Emissions reduction impact

Output: Overall and relative emissions reduction from initiatives annually until 2030

Financial impact

Output: NPV[1] of initiative (considers operational cost impact, revenue impact, capital investment, and other cash impacts e.g., carbon tax) and feasibility assessment (CapEx requirement)

Non-financial measures

Output: Key considerations on ability to recover the cost, impact to society, implementation risk, and other enterprise level considerations (as appropriate)

→

Prioritization framework that is consistent across BUs

Output: Holistic consideration across financial, risk, emissions reduction metrics to assess tradeoffs, as well as broader strategic considerations

→

Decision for final set of initiatives to pursue made by ELT through an enterprise lens

Note: Prioritization will be revisited on an annual basis

A set of criteria will be gathered and used to prioritize initiatives for the next 5 and 10 years

1. Will use Enbridge discount rate for all NPV calculations

3 Draft: 2021 prioritization approach; Intent to align on handful of high impact opportunities

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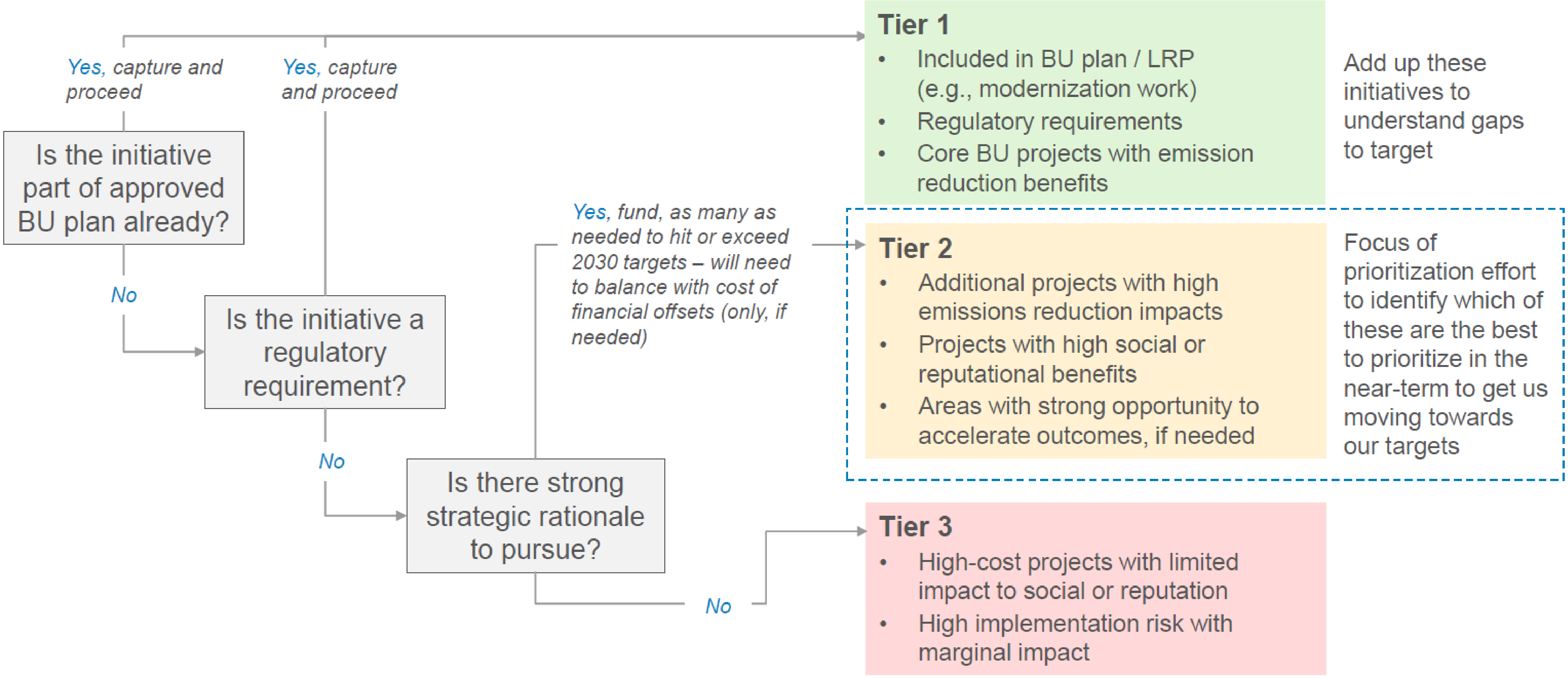

Proposed BU submission template of initiatives

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GDS 2021 10 year forward Emissions Reduction Plan Template

OVERALL BASELINE ASSUMPTIONS	(relevant metrics by BU)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Est. volume														
BAU Baseline Emissions (MM tCO2e)														
BAU Baseline Emissions Intensity														

INITIATIVE VIEW	Overview of initaitives				Prioritization Criteria								
					Emissions reduction		Financial			Non-financial			
Pathway	Project Name	Scope	ISD	Life	Total tCO2	Annual tCO2	Nominal Capital (in C$)	NPV	$/tCO2e	Ability to recover in rate base	Regulatory requirement	Social benefit	Implementation risk
Modernization & Innovation	STO Online Monitoring	Scope 1	2020	25	(31,450)	(1,258)	0			Yes	No	Moderate	Low
Modernization & Innovation	Portable Blowdown Recovery - Transmission	Scope 1	2022	25	(39,825)	(1,593)	3			Potentially	No	Moderate	Low
Modernization & Innovation	Portable Blowdown Recovery - Distribution	Scope 1	2021	25	(600)	(24)	13			Potentially	No	Moderate	Low
Modernization & Innovation	Copper Service Replacement	Scope 1	2020	40	(5,400)	(135)				Yes	No	Moderate	Low
Modernization & Innovation	Station Heating Equipment	Scope 1	2019	20	(28,560)	(1,428)				Yes	No	Moderate	Low
Modernization & Innovation	Direct Inspection and Maintenance Program/LDAR	Scope 1	2019	N/A		(7,507)				Yes	Yes	Moderate	Low
Modernization & Innovation	Fugitive Emissions Management - Reduce Backlogs	Scope 1	2021	N/A		(13,095)				Yes	No	Moderate	Low
Modernization & Innovation	Standardizing Residential Meter Sets - Candy Cane	Scope 1	2019	20	(61,200)	(3,060)				Yes	No	Moderate	Low
Modernization & Innovation	Control Valves (Pneumatic Devices) - High Bleed to low/electric - Tra	Scope 1	2023	40	(218,920)	(5,473)				Yes	Yes	Moderate	Low
Modernization & Innovation	Effective Use of Existing Blowdown Compressors	Scope 1	2021	40	(204,520)	(5,113)				Yes	No	Moderate	Low
Modernization & Innovation	Rod Packing Replacement	Scope 1	2020	10	(21,060)	(2,106)				Yes	Yes	Moderate	Low
Modernization & Innovation	Leak Quantification at Gate Stations	Scope 1	2025	20	(65,340)	(3,267)				Potentially	No	Moderate	Low
Modernization & Innovation	Air Filter Replacement for Turbines	Scope 1	2020	5	(13,500)	(2,700)				Yes	No	Moderate	Low
Modernization & Innovation	TCI 4000 Flare (DO)	Scope 1	2021	TBD		TBD	TBD			Yes	No	Moderate	Low
Modernization & Innovation	Hagar Boil-Off	Scope 1	2024	40	(453,875)	(11,347)	6			Yes	No	Moderate	Low
Modernization & Innovation	Control Valves (Pneumatic Devices) - Distribution	Scope 1	2023	40	(19,160)	(479)				Potentially	No	Moderate	Low
Modernization & Innovation	Odourant Pump - Fuel Gas Release	Scope 1	TBD	TBD		TBD	TBD			Potentially	No	Moderate	Low
Modernization & Innovation	Vented Gas Capture at Compressor Stations	Scope 1	2024	25	(131,975)	(5,279)	9			Yes	No	Moderate	Low
Modernization & Innovation	Electric Drive Compressor - Plant J Twinning	Scope 1	2023	40	(633,720)	(15,843)	70			Potentially	No	Moderate	Medium
Modernization & Innovation	Electric Drive Compressor - Parkway	Scope 1	TBD	TBD		TBD	TBD			Potentially	No	Moderate	Medium
Direct - Other Low-Carbon Solutions	Hydrogen CHP	Scope 3	TBD	TBD		TBD	TBD			No	No	Moderate	High
Modernization & Innovation	NG Replacement - Dawn C Plant	Scope 1	2024	40	(39,639)	(991)	152			Yes	No	Moderate	Low
Modernization & Innovation	NG Replacement - Dawn D Plant	Scope 1	2029	40	(29,268)	(732)	167			Yes	No	Moderate	Low
Modernization & Innovation	NG Replacement - Dawn E Plant	Scope 1	2030	40	(29,888)	(747)	171			Yes	No	Moderate	Low
Modernization & Innovation	NG Replacement - Lobo A1	Scope 1	2030	40	(34,178)	(854)	122			Yes	No	Moderate	Low
Modernization & Innovation	NG Replacement - Lobo A2	Scope 1	2030	40	(27,858)	(696)	122			Yes	No	Moderate	Low
Modernization & Innovation	NG Replacement - Lobo B Plant	Scope 1	2030	40	(46,650)	(1,166)	171			Yes	No	Moderate	Low
Modernization & Innovation	NG Replacement - Bright B Plant	Scope 1	2030	40	(32,075)	(802)	171			Yes	No	Moderate	Low
Modernization & Innovation	NG Replacement - Parkway A Plant	Scope 1	2029	40	(85,475)	(2,137)	120			Yes	No	Moderate	Low
Direct - Other Low-Carbon Solutions	Compressor Fuel Switch to 10% RNG - Dawn/Tecumseh	Scope 1	2023	40	(509,120)	(12,728)				Potentially	No	Moderate	Low
Direct - Other Low-Carbon Solutions	Compressor Fuel Switch to 35% RNG - Dawn/Tecumseh	Scope 1	2023	40	(1,781,840)	(44,546)				Potentially	No	Moderate	Low

Preliminary Working Draft

The templates will be gathered and collated into an Enterprise view for initial prioritization prior to the July SteerCo.

3

Proposed: Elements of the BU template

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Working Draft

Categories		Inputs to Template
Baseline BU Assumptions	Relevant metrics by BU	Est. volume
		BAU Baseline Emissions (MM tCO_2e)
		BAU Baseline Emissions Intensity
Overview of initiatives	Facts on the initiative	Pathway (see prior page for 4 categories included)
		Project Name
		Scope
		Start date
		ISD
		Life
Prioritization Criteria	Emissions reduction impact	Total tCO_2
		Annual tCO_2
		tCO_2/PJ
	Financial implication	Nominal Capital (in C$)
	Non-financial considerations	Ability to recover in rate base
		Regulatory requirement
		Social benefit
		Implementation risk

Next Steps/Discussion:

Prioritization Framework / Financial Assessment:

- To be developed by end of June (pending approval of additional corporate resources)
- Will be used to determine Net Present Value (NPV) and $/tonne cost of projects
- Model may not be consistent with previous models used by GDS for OEB applications
  - Previous modelling based on Federal Carbon Pricing Program (FCPP):
    - Carbon Levy only applies to Fuel Use (e.g., Combustion Emissions)
    - Carbon Cost based on FCPP
    - Carbon Levy for STO Fuel discounted based on Output Based Pricing Program (Carbon Levy discounted by ~ 65%)
  - Engaged Finance/Regulatory/Energy Transition to assist with evaluation of Corporate Prioritization Framework/ Financial Model and applicability to OEB projects and Cost Recovery Potential for any projects to be submitted under FCPP application

Next Steps/Discussion:

New Opportunities/Innovation

- STO fuel usage is largest source of GDS GHG Emissions, representing approximately 40% of total 2018 baseline emissions

- Evaluating opportunities for reducing STO fuel usage, including:
  - ***Business Development/RNG:***
    - Working with Business Development to assess RNG opportunities to offset STO Compressor Fuel usage
    - A preliminary assessment indicates that switching the **Dawn and Tecumseh compressor units** to a blend of natural gas containing:
      - **10% RNG** would result in an overall reduction of **13,000 tCO2e/yr* or a 1.5% reduction in emissions** as compared to the GDS 2018 baseline emissions
      - **35% RNG** would result in an overall reduction of **45,000 tCO2e/yr* or a 5.1% emissions reduction** as compared to the GDS 2018 baseline emissions.
  - ***Compressor Modernization***
    - Strategic Electrification of Compressors
      - Parkway/Parkway West (Small block of HP, infrastructure, noise abatement)
      - Dawn J Twinning (Favourable off-peak electricity pricing)

* Using 3-year average compressor fuel consumption

Energy Transition Advisory Group

Summary of Discussion & Proposed Next Steps

ENBRIDGE
Life Takes Energy

ETAG Member Input / Discussion

- EGI does not yet have an energy transition specific goal and associated plan to achieve it, therefore:
  - Existing working groups and steering committees are effective, but they do not always cover the broader energy transition discussion, so it can be difficult to see how the pieces fit together and what the collective actions can/will achieve in the long term.
  - There could be decisions/endorsements currently happening within sub-committees and work streams that could be raised to the ETAG to ensure alignment and prioritization.
  - Different department's in-year, annual goals aren't consistently set with a longer term EGI Energy Transition goal/plan in mind.

Proposed Approach / Next Steps for the ETAG

1. Scope what an EGI energy transition goal could be, ensuring alignment / support of EI's strategic plans and provincial/federal targets:
   - What could a customer emissions reduction goal/target (Scope 3) be?
   - What could an ex-franchise energy transition goal/target be?

2. Propose EGI energy transition goal(s).

3. Draft associated plan to achieve goal(s)
   - Identify and tie existing ET related activities to achievement of the agreed upon goal(s)?
   - Determine which new EGI initiatives/activities need to be evaluated and prioritized based on how they support achievement of the ET goal(s) and how this will occur.

Post ETAG Meeting Discussion – Scope 3

- EI contacted Energy Transition team to discuss potential / feasibility for GDS to set a Scope 3 reduction target – next steps:
  - High-level assessment to be completed by next week
  - Potential for a more detailed assessment to be requested by fall
    - This could expedite the work discussed with the ETAG and tie into the rebasing work / strategy

Rebasing - Incorporating ET into Demand Forecast

- Discussion held with Regulatory, Finance, BD, ET, DOE, Integrity & Asset Mgmt. to align on rebasing demand forecasting approach/strategy.

- Through discussion, the group determined that core demand forecast assumptions must:
  - Include consideration of energy transition, specifically:
    - Annual customer growth numbers.
    - Average consumption per year.
    - Additional items to be evaluated once the ‘Energy Transition Scenario Analysis’ report is completed/assessed.
  - Include consideration of the IESO’s planning document – to align their capacity plans/constraints with our forecast.
  - *Be brought forward to the ETSC for input prior to finalization.*

Note: Rebasing team to discuss/determine how energy transition will be considered when looking at depreciation, equity thickness.

Carbon Strategy Update

1. Government Consultation Submissions – Jennifer Murphy
2. Energy Transition Scenario Analysis Update – Jennifer Murphy
3. Net Zero Buildings – Heidi Steinberg Laxton
4. IEA's Net Zero by 2050 Report – Heidi Steinberg Laxton

Climate Policy Government Consultations

Jennifer Murphy

ENBRIDGE
Life Takes Energy

Friday, May 28

Climate Policy Update

Topic	Consultation Overview	Date Submitted
Review of the Federal OBPS Regulations	The Government of Canada committed to reviewing the OBPS regulations in 2022 and launched a consultation period seeking input on various aspects of the OBPS regulations for post-2022. Next steps: ECCC will engage stakeholders in the review in late 2021	March 29, 2021
Federal GHG Offset System	The Government of Canada consulting on the draft offset regulations. Next steps: final regulation anticipated in late 2021	May 5, 2021
Federal OBPS Programming	Consultation to inform program design related to federal programing for OBPS proceeds return and ways the programming could support registered facilities' climate action. Next steps: call for proposals anticipated in June/July 2021. Once project eligibility criteria is published, need to determine if EGI has any eligible projects.	May 12, 2021

Climate Policy Update

Recent Submissions

Topic	Consultation Overview	Date Submitted
Hydrogen exemption in GGPPA	Meeting with ECCC and federal Dept. of Finance to discuss hydrogen blending, including lack of exemption for hydrogen blended in natural gas from the federal carbon charge. Next steps: Jennifer and Sam meeting with GR next week to discuss next steps on advocacy.	May 21, 2021
The Clean Fuels Fund	NRCan hosted webinar on May 20 describing eligibility and evaluation criteria related to $1.38B funding program for feasibility/FEED studies and facility construction. Enbridge provided feedback on problematic eligibility criteria (size threshold and off-take agreement requirements). Next Steps: BD to identify projects in preparation for June 31 RFP launch.	May 28, 2021
Climate Action and Awareness Fund	ECCC has launched CAAF that will fund up to $6M in carbon capture and storage research and development to not-for-profit NGOs. Next Steps: Energy Services exploring partnership with Oil, Gas, Salt Resource Library to pursue CO2 injection project funding. GR also preparing brief on current restrictions preventing CO2 storage in Oil, Gas, Salt Resources Act.	Upcoming: June 10, 2021

Energy Transition Scenario Analysis Update

Jennifer Murphy

ENBRIDGE
Life Takes Energy

Friday, May 28

Energy Transition Scenario Analysis

- Consultant has completed modeling of “Steady Progress” scenario and is completing QA/QC checks.
- All scenario output files to be released May 31.
- Accompanying report and Power BI data visualization tool will be delivered mid-June.
- Existing documentation on scenario assumptions and modeling approaches have been shared with forecasting, finance and contract teams.
- On-going discussions with regulatory, forecasting, finance and other groups on how ETSA results may support rebasing application.

Net Zero Buildings Update

Heidi Steinberg Laxton

Net Zero Buildings

- There is a need to bring all EGI groups together to share knowledge and harmonize EGI's approach on net-zero building (NZB) matters. The NZB working group (NZB WG) will provide a means to align EGI's efforts, enhance advocacy efforts and maintain records for NZB.
- NZB WG will be coordinated by Energy Transition, with members from BD, Customer Care, Marketing & Energy Conservation, and GR.
- NZB WG members to be selected by Managers of above-mentioned groups.
- First meeting planned for June.
- Developing NZB WG Charter – draft to be reviewed at first meeting.

Net Zero by 2050 Analysis – IEA Report

Heidi Steinberg Laxton

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Friday, May 28

IEA - Net Zero by 2050 – A Roadmap for the Global Energy Sector, May 2021

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- **Approach to Net Zero by 2050:**
  - Key approach: energy efficiency, behavioural changes, electrification, renewables, hydrogen and hydrogen-based fuels, bioenergy and carbon capture, utilization and storage (CCUS).
  - Energy mix in 2050 is diversified with renewable energy providing two-thirds of energy use, including bioenergy, wind, solar, hydroelectricity, and geothermal, as well as nuclear.
- **Impacts to fossil fuels and natural gas:**
  - Increase in natural gas demand through mid-2020s before its significant decrease by 2050.
  - IEA suggests that no fossil fuel exploration, and no new oil and natural gas fields beyond those already approved for development.
- **Impacts to Buildings Sector:**
  - Electricity becomes dominant energy in buildings in 2050, and two-thirds of residential buildings are fitted with a heat pump. Remainder of building heat from hydrogen, bioenergy, district heat, solar thermal.
  - IEA recommends bans on new fossil fuel boilers (2025) and mandates that new buildings and most old buildings comply with zero-carbon-ready building energy codes (introduced by 2030) with compliance by 2050. By 2025, any gas boilers sold must be capable of burning 100% hydrogen and low-carbon gases (biomethane) in gas distributed to buildings, rises from almost zero to 10% by 2030 to above 75% by 2050.

IEA - Net Zero by 2050 – A Roadmap for the Global Energy Sector, May 2021

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- **Impacts to Industrial Sector:**
  - Emissions reductions are initially observed by 2030 through energy and materials efficiency improvements, electrification of heat, and fuel switching to solar thermal, geothermal and bioenergy. Electricity consumption in industry more than doubles between 2020 and 2050.
  - Hydrogen and hydrogen-based fuels, bioenergy and CCUS play an increasing role in reducing $CO2$ emissions from industry, especially in high-temperature heat application that cannot be readily provided by electricity.
- **Electricity Generation:**
  - Electricity demand doubles by 2050, and comprises of 90% of renewables, with wind and solar PV accounting for ~70% and balance from nuclear.
  - Transition requires more flexibility: batteries, demand response and low-carbon power generation.
  - More stringent fuel-economy standards are created and elimination of internal combustion engines (ICEs) by 2035 results in shift to electric vehicles (EVs), which increases electricity system demand.

IEA - Net Zero by 2050 – A Roadmap for the Global Energy Sector, May 2021

- **Role of Alternative Technologies and Fuels:**
  - Supply of low-emissions gases (i.e., hydrogen, synthetic methane, biogas and biomethane) rises significantly from 2020 to 2050.
  - Reductions in CO_2 emissions through 2030 come from technologies readily available today. In 2050, half the reductions come from technologies that are currently at the demonstration or prototype phase - advanced batteries, hydrogen electrolyzers, and direct air capture and storage, which includes new pipelines to transport captured CO_2 emissions and systems to move hydrogen between ports and industrial zones.
  - Roll-out of hydrogen and CCUS after 2030 require significant annual investment in CO_2 pipelines and hydrogen enabling infrastructure.

IEA - Net Zero by 2050 – A Roadmap for the Global Energy Sector, May 2021

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- **Biogas and Modern Bioenergy**
  - Direct use of renewables expands in all end-use sectors globally through to 2050. Modern bioenergy accounts for the bulk growth with blending of biomethane into natural gas networks and liquid biofuels in transport, which mainly occurs in regions with net zero mandates.
  - Biomethane demand grows due to blending mandates for gas networks, with average blending rates increasing to above 80% in many regions by 2050. One of the key advantages of bioenergy - use existing natural gas pipelines and end-user equipment.
- **Hydrogen**
  - Used to convert existing fossil energy to low-carbon hydrogen (no new transmission and distribution infrastructure required).
  - Hydrogen use expands from 10% in 2020 to 70% in 2030 and is blended with natural gas in gas networks (global average blend in 2030 includes 15% of hydrogen in volumetric terms, reducing CO2 emissions from gas consumption by around 6%).
  - Stored hydrogen is used to help balance demand and seasonal fluctuations, through retrofitting existing gas-fired capacity to co-fire with hydrogen.

IEA - Net Zero by 2050 – A Roadmap for the Global Energy Sector, May 2021

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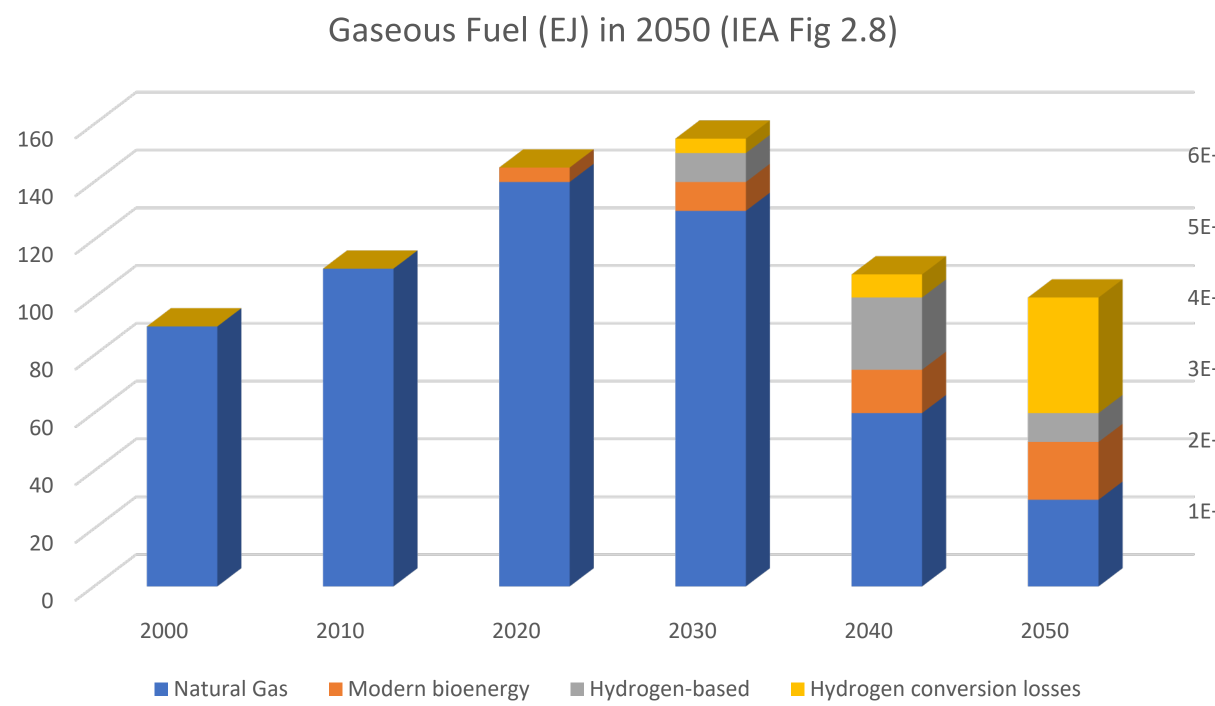
Potential risks:

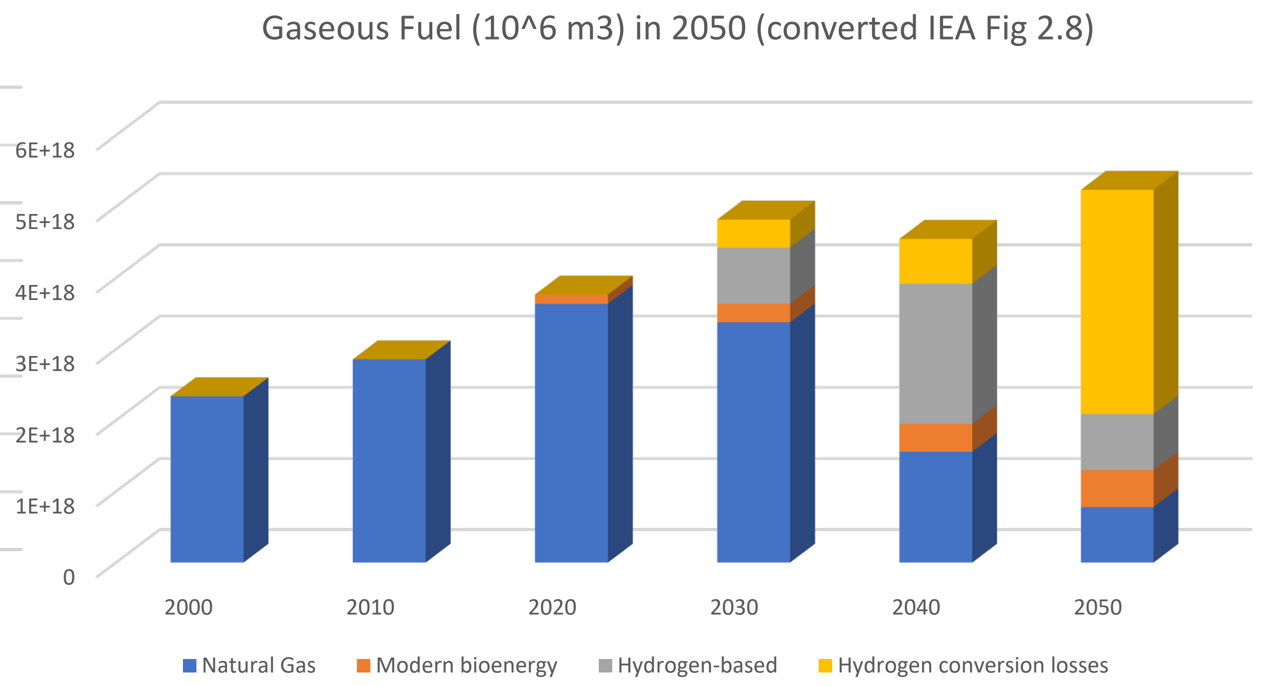
- Low growth of annual gas demand through mid 2020's, with decline on energy basis through 2050 due to behaviour change, energy efficiency and fuel switching.
- Residential/commercial – building heat switches nearly 100% to heat pumps, district thermal, solar thermal, etc. Drop in new builds starting in 2030 with mandate of "zero-carbon ready" buildings.
- Industrial – natural gas remains only where used as a feedstock, or where CCUS can be implemented.
- Stranded assets in natural gas system starting in 2030 and increasing to 2050.

Potential opportunities:

- Growth potential in low emission fuels (RNG, hydrogen), fuel switching technologies (geothermal, heat pumps), CCUS, low emission electricity generation (solar, wind, nuclear), electricity storage (batteries), energy efficiency programing.
  - Greater potential for gaseous solutions if industry can demonstrate role they could play in reaching NZ2050.
- Significant uptake of hydrogen (blending or used on its own) means annual throughput on m^3 basis could be the same/slight increase in 2040-2050.
- Consideration of NZ2050 targets in developing GDS strategy, scope 3 emission targets/plans.

IEA - Net Zero by 2050 – A Roadmap for the Global Energy Sector, May 2021





Natural Gas	Traditional natural gas
Modern bioenergy	Includes biogases, liquid biofuels and modern solid biomass harvested from sustainable sources. It excludes the traditional use of biomass (i.e., cooking)
Hydrogen-based	Includes hydrogen, ammonia and synthetic fuels
Hydrogen conversion losses	Consumption of natural gas when producing low-carbon merchant hydrogen using steam methane reforming

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-3-1, Attachment 2

Question(s):

Please provide the number of test year FTEs that report to each Director level position listed in the Enbridge's organizational chart.

Response:

Please see Table 1.

Table 1
2024 Test Year Number of Test FTE by Director

Line No.	Particulars	FTE
1	Business Development	30
2	Distribution Marketing	14
3	Energy Conservation	182
4	Energy Transition Planning	27
5	Product Development	0
6	Public Affairs & Ombudsmen	47
7	Regulatory Affairs	30
8	Customer Care Operations	194
9	Distribution in Franchise Sales	32
10	Large Volume Contracting & Policy	57
11	S&T Sales	19
12	Gas Control & Management	61
13	Gas Supply	12
14	S&T Business Development	22
15	Utility Portfolio Management	12
16	Eastern Region Ops.	179
17	GTA East Ops.	142
18	GTA West Ops	165
19	Northern Region Ops	191
20	Operations Services & Governance	367
21	Field Services and Growth	243
22	Southeast Region Ops	217
23	Southwest Region Ops	178
24	Toronto Region Ops	184
25	Engineering Services & IMS	118
26	Engineering	151
27	Integrity & Asset Management	134
28	System Improvement	189
29	Transmission Compression & LNG Operations	240
30	Total FTE report under Director(1)	3436

Notes:
(1) There are 34 FTEs that do not report to the directors listed in the referenced Attachment

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 4, Schedule 1

Preamble:

“1. Enbridge Gas has over $14 billion in regulated assets…”

Question(s):

a) Please provide the exact figure quantifying Enbridge’s regulated assets in Ontario.

b) With respect to its current assets, by what year would they be fully depreciated based on the proposed depreciation policies/periods proposed by Enbridge in this application?

c) With respect to its current assets, how much ($) would remain undepreciated in 2050 under the proposed depreciation policies/periods proposed by Enbridge?

Response:

a) Please see Exhibit 2, Tab 2, Schedule 1, pages 3 to 4, updated March 8, 2023. Regulated asset, or utility property, plant & equipment balances are summarized in Table 1:

Table 1

		2021	2022	2023	2024
($ millions)	Reference	Actual	Estimate	Bridge Year	Test Year
Gross Property, Plant & Equipment	Pg 3, line 6	22,221.4	23,535.2	24,831.5	25,791.8
Accumulated Depreciation	Pg 4, line 7	(8,126.9)	(8,626.9)	(9,137.7)	(9,436.7)
Net Property, Plant & Equipment		14,094.5	14,908.3	15,693.8	16,355.1

b) Using the proposed depreciation policies in this application and assuming the current depreciable assets (Plant in service at December 31, 2021) are fully intact without any damages and replacements, the current assets will be fully depreciated in 2067.

c) Using the proposed depreciation policies in this application and assuming the current depreciable assets (Plant in service at December 31, 2021) are fully intact without any damages and replacements, the value of undepreciated assets in 2050 is $569.7 million.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

1/4/1 para 1 - Enbridge Gas has over $14 billion in regulated assets and serves over 3.8 million residential, commercial, and industrial customers in Ontario delivering heating to more than 75% of Ontario's homes". [Exhibit 1, Tab 4, Schedule 1, Paragraph 1]

Question(s):

a) Please provide a breakdown by major category of the $14 billion in regulated assets (e.g. pipelines, buildings, IT, etc.)

b) Please confirm that the $14 billion reference refers to regulated assets regulated by the Ontario Energy Board. If not, please clarify what portion is regulated by the Ontario Energy Board and replicate the answer for part "a" with the portion of assets regulated by the Ontario Energy Board.

Response:

a) A breakdown by major category of regulated assets is provided at Exhibit 2, Tab 2, Schedule 1, Attachments 3 through 8 for the historical years 2019 through 2021 and forecast years 2022 through 2024.

b) Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

Please provide a table showing all capital projects (e.g. Leave to Constricts, etc.) approved by the OEB since last rebasing (i.e. MAADs proceeding and Decision), where capital recovery is requested in this proceeding (EB-2022-0200). In the table, please provide the following columns of information:

- Project name
- OEB docket number
- Total capital cost (forecasted / actual)
- Capital O/H amount (if included in total project capital cost)
- In-service date (actual or expected)
- Amortization period

Response:

Please see Attachment 1.

Table 1

Project Name	Applicant	Docket Number	Total Capital Cost (Forecasted)	Total Capital Cost (Actual)	Capital Overhead Amount	In-Service Date (Actual or Expected)	Amortization Period
2018 Oxford Reinforcement Project	Union Gas	EB-2018-0003	$ 7,396,000.00	$ 4,662,754.00	$ 872,294.84	October 4, 2018 (Actual)	55 years
Kingsville Transmission Reinforcement Project	Union Gas	EB-2018-0013	$ 105,716,000.00	$ 77,042,559.00	$ 15,440,932.60	October 24, 2019 (Actual)	60 years
Liberty Village Project	Enbridge Gas Distribution	EB-2018-0096	$ 3,623,263.00	$ 4,151,681.00	$ 1,124,045.73	March 28, 2019 (Actual)	55 years
Bathurst Reinforcement Project	Enbridge Gas Distribution	EB-2018-0097	$ 9,147,651.00	$ 9,442,615.00	$ 3,237,782.72	December 11, 2019 (Actual)	55 years
Don River 30" Pipeline Project	Enbridge Gas Distribution	EB-2018-0108	$ 25,318,141.00	$ 23,706,759.00	$ 7,394,061.65	April 21, 2020 (Actual)	55 years
Chatham-Kent Rural Project	Enbridge Gas Distribution	EB-2018-0188	$ 19,100,000.00	$ 14,797,695.00	$ 1,286,671.24	November 22, 2019 (Actual)	55 years
Georgian Sands Pipeline Project	Enbridge Gas Inc	EB-2018-0226	$ 2,827,537.00	$ 2,112,532.00	$ 623,330.48	June 1, 2020 (Actual)	55 years
Stratford Reinforcement Project	Enbridge Gas Distribution	EB-2018-0306	$ 28,540,000.00	$ 24,796,716.00	$ 4,217,375.69	September 14, 2019 (Actual)	60 years
St Laurent Pipeline Project	Enbridge Gas Inc	EB-2019-0006	$ 5,510,519.00	$ 6,546,818.00	$ 1,927,394.47	September 4, 2020 (Actual)	60 years
Windsor Line Replacement Project	Enbridge Gas Inc	EB-2019-0172	$ 106,805,000.00	$ 82,929,806.00	$ 14,690,069.06	September 10, 2021 (Actual)	55 years
Owen Sound Reinforcement Project	Enbridge Gas Inc	EB-2019-0183	$ 68,965,000.00	$ 70,121,772.00	$ 11,959,209.96	October 20, 2020 (Actual)	60 years
Saugeen First Nation Community Expansion	Enbridge Gas Inc	EB-2019-0187	$ 2,537,360.00	$ 3,058,999.00	$ 2,132.13	August 24, 2020 (Actual)	60 years
North Bay Community Expansion Project	Enbridge Gas Inc	EB-2019-0188	$ 10,095,250.00	$ 11,861,640.00	$ 37,664.98	October 1, 2021 (Actual)	60 years
Sarnia Reinforcement Project	Enbridge Gas Inc	EB-2019-0218	$ 30,761,000.00	$ 36,966,604.00	$ 6,631,845.22	November 1, 2021 (Actual)	60 years
Low Carbon Energy Project	Enbridge Gas Inc	EB-2019-0294	$ 5,232,265.00	$ 6,779,329.00	$ 1,256,973.56	October 1, 2021 (Actual)	55 years
NPS 20 Replacement Cherry to Bathurst Project	Enbridge Gas Inc	EB-2020-0136	$ 133,047,891.00			December 8, 2022 (Actual)	55 years
London Lines Replacement Project	Enbridge Gas Inc	EB-2020-0192	$ 164,098,000.00			December 10, 2021 (Actual)	55 years
Greenstone Pipeline Project	Enbridge Gas Inc	EB-2021-0205	$ 25,777,789.00			March 2023 (Expected)	55 years
Waterfront Toronto Relocation Project	Enbridge Gas Inc	EB-2022-0003	$ 23,461,558.00			August 2024 (Expected)	55 years
Dawn to Corunna Pipeline Project	Enbridge Gas Inc	EB-2022-0086	$ 250,749,703.00			November 1, 2023 (Expected)	55 years
Haldimand Shores Community Expansion Project	Enbridge Gas Inc	EB-2022-0088	$ 4,048,709.00			February 8, 2023 (Actual)	55 years
Coveny and Kimball-Colinville Well Drilling Project (Gathering Lines)	Enbridge Gas Inc	EB-2021-0248	$ 5,076,600.00			September 9, 2022 (Actual)	55 years

Data Sources:
Total Capital Cost (Actuals) taken from Post Construction Financial Reports filed with the OEB either in their respective proceedings or at 1.21.1 of the EB-2022-0200 evidence.
In Service dates were filed in their respective proceedings as a requirement of the Conditions of Approval.
The list of Projects includes all Projects with a docket number from 2018-current that required Section 90(1) Leave to Construct Approval.

Not Required... Actuals will be filled in PCFR at a later date
Includes Indirect OH, IDC & Loadings
Includes IDC & Loadings - Project not allocated Indirect OH

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association (QMA)

Interrogatory

Reference:

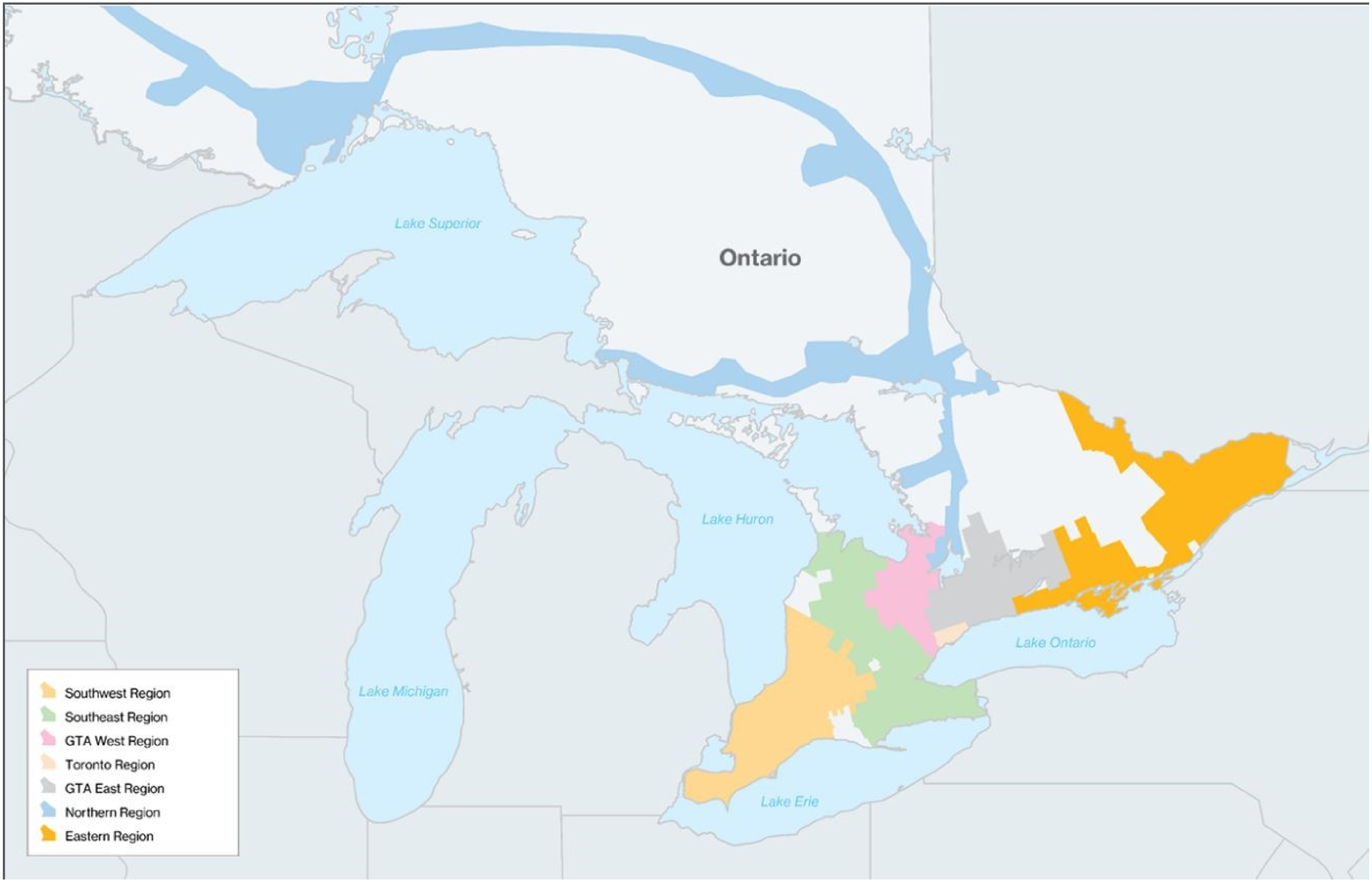
Ref: E1/T4/S1

Question(s):

Please provide an Enbridge system map that shows the new boundaries of the Company's operating regions in Ontario.

Response:

Please see Attachment 1 for a system map showing the boundaries of the Company's operating regions in Ontario. The operating regions shown in Attachment 1 align with the detailed system map provided at Exhibit 1, Tab 4, Schedule 1, Attachment 1.


Ontario
Lake Superior
Lake Huron
Lake Michigan
Lake Ontario
Lake Erie
Southwest Region
Southeast Region
GTA West Region
Toronto Region
GTA East Region
Northern Region
Eastern Region

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-5-1, p.11

Question(s):

Please provide all studies, memoranda, presentations and other documents related to the relationship between the proposed straight fixed variable with demand rate design and the availability and economics of demand response programs.

Response:

Please see Exhibit 8, Tab 2, Schedule 3, pages 1 to 37, and Attachments 1 through 10 for the evidence, reports, studies, and presentations supporting Enbridge Gas' proposals. The key benefits of the Straight Fixed Variable with Demand (SFVD) rate design alternative and SFVD characteristics that are complementary to energy transition goals are provided at Exhibit 8, Tab 2, Schedule 3, pages 14 and 15. This evidence will be addressed in Phase 2 of the proceeding as noted in Enbridge Gas's February 1, 2023 letter.

Natural gas demand response programs are not yet well-established in Ontario, and therefore Enbridge Gas is not aware of any studies or other documents specifically related to the relationship between the proposed rate design and the economics of demand response programs.

Enbridge Gas will be proposing an IRP pilot where a demand response program will be developed and implemented to gather information and learnings for program marketing, program development, customer incentives, the calling of a demand response event and customer participation. Enbridge Gas's IRP demand response pilot program will provide a financial incentive to those general service customers participating in the program and who reduce their consumption when a demand response event is called. All participants receiving this incentive will benefit regardless of rate design. Even without an incentive, under a SFVD rate structure, "volumetric charges still make up the largest portion (generally at least 60%) of total customers' bills" (Exhibit 8, Tab 2, Schedule 3, paragraph 39), so there is still a built-in incentive to participate in demand response programs under SFVD.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1

Question(s):

Enbridge Gas conducted a customer engagement process through 2021 and early 2022 to understand customer needs and preferences to inform its business planning process. Enbridge Gas explored customer perceptions of key planning trade-offs, overall rate impacts of its draft plan, and rate design issues.

Acknowledging that Enbridge Gas's last customer engagement survey used different survey instruments and methodologies, to the extent possible, please identify any differences or similarities in customer preferences from the last survey.

Response:

Comparing the two engagements (the current customer engagement conducted through 2021 and early 2022, and the EGI 2019 Asset Management Plan Customer Engagement), similar questions related to satisfaction, outcomes and investment priorities were asked. Where a comparison was relevant, any differences and similarities are noted in the paragraphs below.

Customer satisfaction: Customer satisfaction with Enbridge Gas was similar across the two customer engagements, ranging from 74% to 88% among the different customer segments in both engagements. Customer satisfaction provides an indicator of customer preferences as it relates to the services received to date.

Outcomes overall summary: While the list of outcomes varied slightly between the two customer engagements, both engagements included a process of rating the importance of outcomes and ranking the ones that are most important. While the same outcomes rise to the top, their placement varies slightly between the two engagements.

Outcomes – general service residential: Among the outcomes rated as the most important, similar outcomes rose near the top for residential customers, including affordable pricing, safety, reliability and minimizing any impacts on the environment.

The order of these varied slightly, with the current engagement seeing affordable pricing at the top, which was second to safety in the previous engagement. Reliability was mentioned fifth in the previous engagement but rose to third place in the current engagement (though nearly the same as minimizing any impacts on the environment). Being socially responsible was consistently near the bottom of the list.

Outcomes – general service business: Among general service business customers, results in the current engagement were disaggregated by small and medium-large customers. Comparing this entire group to the “non-contract business customer” group in the last engagement, affordable pricing is still at the top of the list, followed by safety and reliability, with predictable pricing and minimizing any impacts on the environment following these top three in varied order.

Outcomes – contract: Among contract customers, reliability consistently topped the list of outcome priorities between the two engagements, followed by affordable pricing, while safety was third in the recent engagement, but followed fourth after stable and predictable in the previous engagement.

Investment priorities: The majority of residential and business customers across engagements would prefer that Enbridge Gas invest in maintaining levels of safety, reliability, and customer service vs improving them. Among these three areas, a greater proportion of residential customers preferred improving levels of safety (more than 1-in-3 in the current engagement), while among business customers, it was customer service (more than 1-in-3 in the current engagement). This is consistent in the two engagements.

In both engagements, customers were presented with a high-level trade-off between a long-term approach to asset health (that spreads out costs over time) versus a more immediate approach (that seeks to keep rates low now), and results were almost identical. Almost 3-in-5 residential customers and just over 1-in-2 business customers (with support being stronger among medium-large business customers in Phase Two in the most recent customer engagement and being stronger among contract customers in the previous customer engagement). Please note this question was not asked among Contract Customers in the most recent customer engagement process.

Among specific investment pacing decisions, across engagements, customers preferred Enbridge Gas to complete the work within the time period indicated rather than delay it as long as possible.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1, p. 14

Question(s):

Enbridge Gas noted that customers participating in the customer engagement survey were given the option to receive follow-up information from Enbridge Gas (after the conclusion of Phase Three) about how customer feedback was used and the overall outcomes of the customer engagement.

a) Please provide a copy of the follow-up information provided by Enbridge Gas to participants following the conclusion of Phase Three.

b) Please confirm if participants had an opportunity to provide feedback on the follow-up information provided by Enbridge Gas. If not, please explain why. If feedback was provided, please provide a summary of the feedback received including any issues and concerns raised and how they were addressed by Enbridge Gas in this application. Also, please explain whether and how any feedback has impacted Enbridge Gas's business and capital planning.

Response:

a) Please see Attachment 1.

b) There was no official mechanism for general service customers to provide feedback on the follow-up information. The intention of the follow-up information was to summarize feedback already collected and to inform customers of next steps in the process. For the contract market, customers were directed to talk to their account manager. Feedback received from contract rate customers was with respect to the service harmonization proposals. No feedback was received from contract rate customers with respect to the issues being dealt with in this phase of the proceeding.

General Service Customers Follow-up Email

ENBRIDGE
Life Takes Energy

Valued customer,

Thank you for your interest and participation in the customer engagement that focused on understanding customer needs and preferences as Enbridge Gas develops its business plan for 2024 and beyond. These plans will determine the investments that Enbridge Gas makes and will be submitted to the Ontario Energy Board in the last quarter of the year.

Since you've requested to be kept informed about this consultation, we'd like to share some results.

Visit enbridgegas.com/customerengagement to view the results of our customer engagement.

Thank you again for your time and input into this planning process. Your feedback is invaluable and will help shape our plans and will be used to help develop the products and services we provide to our customers.

Thank you,

Enbridge Gas Inc.

Enbridge Gas' Customer Engagement Survey Feedback

More than 12,000 customers participated in our customer engagement process to ensure that our 2024 planning process reflects customers' needs and preferences. Participants were presented with information on our proposals as part of our 2024 – 2028 rate application process.

All individual responses were held in confidence and feedback was combined with others to protect our customers' privacy.

Level of satisfaction

Overall, customers consistently reported high levels of satisfaction with Enbridge Gas with 4-in-5 residential customers indicating they are "very" or "somewhat" satisfied, and 3-in-4 business customers indicating the same.

Improvements

When asked what Enbridge Gas can do to improve their service, most participants did not offer any comments, but about 1-in-10 say keeping rates low is important.

Approach

Enbridge Gas outlined the plan's high-level objectives in the engagement, and more than 2-in-3 customers indicated that these objectives seemed like the "right approach".

Support for the plan

Enbridge Gas outlined specific plans it is considering alongside some alternatives it could do instead. Anticipated rate impacts were included for each choice. So far, customers have supported the plans Enbridge was considering, or an alternative that would require a bigger investment. However, these plans are still under development and all varied perspectives will be considered.

Topics covered

Customers provided detailed comments covering a large number of topics. These range from questions about rates and expenditures, to some issues with customer service, to considerations related to the future of natural gas and the need for low-carbon options, to many other topics.

Next steps

Enbridge Gas will file our rate planning process along with the customer engagement feedback and a summary report to the OEB. This information will be examined by the OEB, consumer advocates and other independent parties in a public hearing.

Large Volume Newsletter Excerpt

Enbridge Gas' Contract Customer Engagement Survey Feedback

Enbridge Gas undertook a customer engagement process designed to understand customers' needs and preferences as it develops its plans for 2024 and beyond. These plans will determine the investments that Enbridge Gas makes and will be submitted to the Ontario Energy Board.

At the beginning of February, the signing authority for each of our in-franchise contract rate and direct purchase customers and marketers received an email invitation to complete a survey workbook. The survey included questions about Enbridge Gas' business plans and service harmonization proposals.

More than 12,000 customers, including more than 80 contract customers and energy marketers, participated in our overall customer engagement process to ensure that our 2024 planning process reflects customers' needs and preferences. Participants were presented with information on our proposals as part of our 2024 – 2028 rate application process.

All individual responses were held in confidence and feedback was combined with others to protect our customers' privacy. Visit enbridgegas.com/contract-engagement to find more information on the feedback we received.

Thank you to everyone who participated.

If you have any questions about any of the material in this newsletter, please contact your account manager.

Home / About Enbridge Gas

Enbridge Gas' Contract Customer Engagement Survey Feedback

More than 12,000 customers, including more than 80 contract customers and energy marketers, participated in our overall customer engagement process to ensure that our 2024 planning process reflects customers' needs and preferences. Participants were presented with information on our proposals as part of our 2024 – 2028 rate application process.

All individual responses were held in confidence and feedback was combined with others to protect our customers' privacy.

Level of satisfaction

Overall, customers, contract and non-contract alike, consistently reported high levels of satisfaction with Enbridge Gas with 4-in-5 contract customers indicating they are "very" or "somewhat" satisfied with Enbridge Gas.
Customer service and the reliability of its distribution services are also rated very highly among contract customers.
Among priority outcomes, reliability, affordable pricing and safely delivering natural gas are of most importance, followed by minimizing any impacts on the environment.

Improvements

When asked what Enbridge Gas can do to improve its service, participants commented on a number of different things, including more information and improvements in communications and customer service.

Approach

Enbridge Gas outlined the plan's high-level objectives in the engagement, and more than 4-in-5 customers indicated that these objectives seemed like the "right approach".

Support for the plan

Enbridge Gas outlined specific plans it is considering alongside some alternatives it could do instead. Anticipated rate impacts were included for each choice. So far, customers have supported the plans Enbridge Gas was considering, or an alternative that would require a bigger investment. However, these plans are still under development and all varied perspectives will be considered.

Service harmonization

Customers provided feedback and comments on various contract rate distribution services and direct purchase service proposals. These comments help Enbridge Gas refine its draft plans to ensure it meets customer needs and will be considered in the development of its proposals.

Next steps

Enbridge Gas will file its rate planning process along with the customer engagement feedback and a summary report to the OEB. This information will be examined by the OEB, consumer advocates and other independent parties in a public hearing.

Please contact your account manager if you would like to share any further thoughts or comments.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1, Attachment 1, pp. 137 & 280; Exhibit 8, Tab 3, Schedule 1, p. 12

Question(s):

Enbridge Gas is proposing an extra length charge of $122 per metre in excess of the 20-metre service length threshold.

When engaged on the topic of Enbridge Gas's Infill Policy, the Phase Two results found that 38% of residential participants either did not have an opinion or indicated "don't know".

The Phase Three results found that 32% of participants indicated a preference for 15 metres at no cost and $75 per metre for the remainder, 22% indicated a preference for 20 metres at no cost and $100 per metre for the remainder, 13% indicated a preference 25 metres at no cost and $140 per metre for the remainder, and 32% either did not have an opinion or indicated "don't know".

a) Did Enbridge Gas probe the results further to understand why 38% of participants in Phase Two, and 32% of participants in Phase Three, did not have an opinion or indicated "don't know"?

b) Please explain why the option in Phase Three for 20 metres at no cost and $100 per metre for the remainder did not more accurately reflect Enbridge Gas's request to charge $122 per metre in excess of the 20-metre service length in this application.

c) Please explain why Enbridge Gas did not consider offering 15 metres at no cost with a lower cost per metre for the remainder considering participants generally preferred this option.

Response:

a) Yes. The workbook gave respondents the opportunity to provide additional comments. An overview of the submitted comments are provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 281.

b) When the Phase Three customer engagement workbook was fielded the estimated cost was determined to be $100 per metre with 20-metre service at no cost to the customer. The cost was subsequently updated to $122 per metre after the fieldwork was completed.

c) Enbridge Gas considered 15 metres (approximately 55% of the total number of infill services) at no cost with a lower cost per metre. The proposed service length threshold of 20 metres would result in the Company attaching most infill services (approximately 75% of the total) with no accompanying extra length charge. This anticipated outcome will support continued efficiencies in the infill service attachment process without causing undue cross-subsidization.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1, Attachment 1, pp. 20 & 25

Question(s):

When engaged on the topic of investing in an Innovation and Technology fund, the Phase Two results found that 37% of residential participants, 48% of small business participants and 52% of medium-large business participants were not willing to pay anything extra towards a technology fund.

When engaged on the same topic in Phase Three, the results found that over half of the participants in all customer segments were willing to pay additional amounts towards a technology fund.

a) Please reconcile the two results and explain the inconsistency.

b) Please confirm if Enbridge Gas undertook further research or analysis to understand the inconsistent results.

c) Please explain how Enbridge Gas considers the above noted results to be valid.

Response:

a) The costs presented in the Phase Two survey (ranging from $12 to $120 per year for residential customers, and 2% to 10% added to the delivery portion of the bill of business customers) were significantly higher than in the Phase Three workbook (ranging from $0.26 to $2.56 per year, and 0.003% to 0.029% added to the delivery portion of the bill of business customers). Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 150, 214-215, 260, 347. Enbridge Gas believes the results differed because the costs presented in each phase differed.

b) Per the response to part a), Enbridge Gas does not consider the results to be inconsistent.

c) Per the response to parts a) and b), Enbridge Gas believes that the results in Phase Three are valid.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1, Attachment 2, p. 26

Question(s):

Enbridge Gas undertook a customer engagement process with Rate M13 customers using a workbook-style survey. A total of seven M13 customers participated in the survey.

a) How many Ontario conventional natural gas producers are Rate M13 customers of Enbridge Gas?

b) How many of the seven participants were Ontario conventional natural gas producers?

c) How many of the seven participants are Rate M13 customers of Enbridge Gas?

Response:

a) There is currently one Ontario conventional natural gas producer that is a Rate M13 customer of Enbridge Gas.

b) One of the seven participants was an Ontario conventional natural gas producer.

c) Five of the seven participants are Rate M13 customers of Enbridge Gas.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1, Attachment 1, p. 32

Question(s):

When engaged on the topic of Renewable Natural Gas (RNG), the Phase Three results found that the majority of residential and business customers were willing to pay more to increase the amount of RNG in the system. However, the two most popular choices were to increase the amount of RNG to only 2% (22% of residential participants, 25% of business participants) or not add any at all (25% of residential participants, 23% of business participants).

Did Enbridge Gas probe the results further to understand why 25% of residential participants and 23% of residential participants indicated a preference not to add any RNG to the gas supply?

Response:

Yes. The workbook gave respondents the opportunity to provide additional comments on each substantive question in the workbook, including the RNG question. An overview of the submitted comments is provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 295 and 385.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T3/S1/Attachment 2/p. 7

Question(s):

Please provide a complete description of the roles and responsibilities of the Director Energy Transition Planning and the group this individual oversees.

Response:

The Director of Energy Transition Planning (ETP) is accountable for leading three teams:

1. Carbon and Energy Transition Planning
2. Carbon Strategy
3. Integrated Resource Planning

The roles within the team and the responsibilities for each team are provided below.

Carbon and Energy Transition Planning

The Carbon and Energy Transition Planning team (formerly called Carbon Strategy) is responsible for implementing and ensuring compliance with carbon pricing policies, which currently includes the Federal Carbon Pricing Program (FCPP) and the Ontario Emission Performance Standards (EPS). These accountabilities include determining compliance costs and remittance amounts, the annual regulatory application, credit procurement and customer communications. The team is also responsible for the implementation of Enbridge Gas's voluntary participation in the federal Clean Fuel Regulation (CFR).

This team is also responsible for reviewing new and changing climate policies and evaluating what the policies could mean for the Company, providing input to government-led consultations, and providing insight on the policies to other internal departments to support initiatives such as RNG and hydrogen blending. This team also uses knowledge on climate policies to develop energy transition assumptions for use in forecasting and planning.

This team works with several other departments within Enbridge Gas to coordinate the development of plans and strategies related to energy transition and reducing Scope 3 greenhouse gas (GHG) emissions. This includes working with Business Development, Gas Supply, Finance, Regulatory, Engineering, Government Relations and others.

The roles and responsibilities of the Carbon and Energy Transition Planning team are provided in Table 1. Currently there are 6.5 FTE roles in the Greenhouse Gas Emissions Administration Deferral Account (including 0.5 of the Director) and 1 FTE role in O&M. In 2024, all roles will be in O&M, plus 1 additional FTE that Enbridge Gas anticipates will be required. Please see response at Exhibit I.9.1-Staff-251.

Table 1: Roles and Responsibilities of the Carbon and Energy Transition Planning Team

Role	Number of FTEs	Responsibilities
Manager	1	Leads Enbridge Gas's carbon pricing compliance activities under the Federal Carbon Pricing Program (FCPP), including reviewing and approving FCPP related compliance reporting and remittance. Leads the work related to Enbridge Gas's energy transition plans, including understanding the impacts of federal and provincial regulations related to greenhouse gas (GHG) requirements for Enbridge Gas.
Specialist	4	Accountable for understanding the potential impacts of federal, provincial and municipal policies and regulations related to GHG emissions, climate change and energy transition for Enbridge Gas. This includes understanding how emerging low-carbon technologies and fuels, such as RNG and hydrogen, can be used to reduce GHG emissions and lower carbon pricing costs. Responsible for developing Enbridge Gas's Clean Fuel Regulation (CFR) strategy and credit creation opportunities. Participate in government consultation for policy development and regulation amendments associated with federal and provincial regulations related to GHG emissions. Lead development of energy transition plans that incorporate the impacts of federal and provincial regulations related to GHG emissions.
Advisor	2	Responsible for FCPP related compliance reporting and remittance, customer registration and communications, annual regulatory requirements, credit procurement process, government consultation submissions for FCPP-related policy development and regulation amendments. Supports the review and evaluation of credit creation opportunities under the CFR. Supports specialists' activities listed above.

Carbon Strategy

The Carbon Strategy team is responsible for development of Enbridge Gas's scope 1 and 2 GHG reduction plan, reporting of GHG emissions to federal and provincial government, tracking and forecasting GHG emissions, performance metrics and emission reductions. This team is responsible for reviewing GHG emissions regulations, evaluating and understanding the impact of the regulations on the Company, and providing input to government-led consultations.

The Carbon Strategy team is also responsible for implementing and ensuring compliance with GHG and methane regulations, which currently includes the Ontario Emissions Performance Standard and the federal Methane Regulation.

The roles and responsibilities of the Carbon Strategy team are provided in Table 2. The 4 FTE roles listed below are currently in Enbridge Gas's O&M budget.

Table 2: Roles and Responsibilities of the Carbon Strategy Team

Role	Number of FTEs	Responsibilities
Manager	1	Leads Enbridge Gas's overarching strategy and plans for reducing Scope 1 and 2 GHG emissions, including overseeing the Enbridge Gas GHG Emissions Reduction Program – Scope 1 and 2. Accountable for Enbridge Gas's GHG emissions reporting and understanding new and changing federal and provincial regulations related to the Company's Scope 1 and 2 greenhouse gas emissions.
Specialist	2	Coordination of GHG Emissions Reduction Program – Scope 1 and 2 across Enbridge Gas. Responsible for greenhouse gas and criteria air contaminant compliance reporting and participating in consultations regarding federal and provincial regulations related to greenhouse gas emissions.
Analyst	1	Responsible for emissions inventory and regulatory requirements related to greenhouse gas and criteria air contaminants.

Integrated Resource Planning (IRP)

The OEB issued an IRP Framework as part of its Decision in EB-2020-0091. The IRP team, within the ETP department, is responsible for implementing the IRP Framework and coordinating the key aspects of the IRP Decision. This activity includes strategic oversight and coordination of IRP binary screening, IRP evaluations, selection of IRP alternatives (IRPAs), IRP pilot projects, IRP non-pilot IRP plans, IRP Stakeholder

Engagement, Enbridge Gas IRP technical working group (TWG) related activities and the IRP Annual Report.

The IRP roles that are within the Energy Transition Planning Department, and their associated responsibilities, are provided in Table 3. Currently there are 2 FTE roles in the IRP deferral account and 3.5 FTE roles in O&M (including 0.5 of the Director). In 2024, all roles will be in O&M. Please refer to Exhibit I.9.1-Staff-249, for additional IRP resourcing details.

Table 3: Roles and Responsibilities of the IRP Team

Role	Number of FTEs	Responsibilities
Manager	1	Leads Enbridge Gas's overarching strategy, integration and planning for IRP, including stakeholder engagement, the technical review and evaluation of IRPA projects. Accountable for Enbridge Gas' participation in the IRP Technical Working Group.
Specialist	2	Lead, support and coordinate stakeholder and Indigenous engagement activities and digital strategy as they relate to IRP activities. Responsible for the development and filing of the annual IRP Report. Supports other departments in the refinement of enhancements to the DCF+ test. Develop evidence for Ontario Energy Board regulatory filings/ proceedings related to IRP and facility projects. Support the implementation of two IRP alternative pilot projects and IRPA Plans (when implemented). Project manage internal activities associated with IRP projects and Leave-to-Construct applications. Participate in the IRP technical working group.
Advisor	2	Supports specialists' activities listed above. Support stakeholder and Indigenous engagement activities as they relate to IRP projects. Support the development and filing of the annual IRP Report. Coordinate the IRP digital strategy. Support the technical review and evaluation of facilities projects and IRP alternatives. Develop evidence for Ontario Energy Board regulatory filings/proceedings related to IRP projects. Support the implementation of two IRP alternative pilot projects. Project manage internal activities associated with IRP projects and Leave-to-Construct applications

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T6/S1/p. 3

Question(s):

The evidence refers to Enbridge Gas's Customer and Market Insights Team (CMI). Who is on the CMI Team? Please explain the nature of the CMI Team's involvement in the Innovative Research work at each stage of that work. Overall, what was EGI's involvement in the Innovative Research work?

Response:

The Customer and Market Insights (CMI) team is composed of the following positions in addition to a recently vacated second Senior Analyst position:

Karen Sweet, Supervisor
Senior Advisor
Advisor
Advisor
Senior Analyst

The nature of the CMI's team overall involvement in the research work undertaken by Innovative Research Group (Innovative) is provided at Exhibit 1, Tab 6, Schedule 1, page 3. Overall, CMI led the customer engagement process and was the primary contact for Innovative at Enbridge Gas. The CMI team designed the engagement and reviewed the design with Innovative. The CMI team worked with Enbridge Gas business planners to identify topics and to develop questions and background information at each phase of the engagement. As specific engagement elements were developed, Innovative provided feedback on the overall approach and specific content as well as testing and providing feedback on the overall surveys and workbooks. Innovative was solely responsible for data collection and reporting the results. Once the results were available, the CMI team distributed them to Enbridge Gas business planners and assisted in the interpretation of the findings. For each specific stage or phase of the process, involvement from the CMI team and Innovative is provided in Table 1.

Table 1: Summary of the CMI Team's involvement in the Innovative Research Work by Stage

#	Customer Engagement Phase	Primary Tasks Completed by CMI Team	Primary Tasks Completed by Innovative
1	Phase One (Development)	• Overall oversight and project management • Overall engagement design • Development of discussion/interview guides with input from Innovative Research • Providing customer lists for sample as needed • Distribution of results to Enbridge Gas business planners • Support to Enbridge Gas business planners in interpreting results	• Reviewing and providing feedback on overall approach and discussion/interview guides • Recruiting customers for focus groups and interviewers • Executing and moderating focus groups and interviews, including test groups • Developing reports
2	Phase Two (Refinement)	• Overall oversight and project management • Overall engagement design • Development of surveys with input from Innovative Research • Providing customer lists for sample as needed • Distribution of results to Enbridge Gas business planners • Support to Enbridge Gas business planners in interpreting results	• Reviewing and providing feedback on overall approach and survey content • Testing surveys • Fielding surveys • Developing reports
3	Phase Three (Validation)	• Overall oversight and project management • Overall engagement design • Development of workbooks in collaboration with Innovative Research • Providing customer lists for sample as needed • Distribution of results to Enbridge Gas business planners • Support to Enbridge Gas business planners in interpreting results	• Reviewing and providing feedback on overall approach and workbook content • Testing workbooks • Fielding workbooks • Developing reports

Overall, Enbridge Gas's involvement includes the work undertaken by the CMI team described above and work done by Enbridge Gas business planners in terms of developing content for the discussion/interview guides, surveys and workbooks.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T6/S1/p. 14

Question(s):

The Phase Three reports prepared by Innovative were shared with all Enbridge Gas teams as soon as they were available. For the Residential Representative Report an interim report was made available to all project stakeholders in mid-December, with final reports being shared in early 2022. Please explain what changed between the interim and final reports. Why were these changes made?

Response:

An additional 1256 respondents completed the survey after data was pulled to generate the interim version of the Residential Representative Report. These additional responses were reflected in the final version of the report but did not significantly alter the findings. This approach gave Enbridge Gas planners the opportunity to consider the interim results while the complete data set was finalized.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1, Attachment 1, p. 6 of 550.

Question(s):

At page 4, Innovative stated that "Most customers are willing to accept the average 1.9% price increase resulting from Enbridge Gas draft plan." See also page 275 of 550, page 247 of 550 and page 330 of 550.

a) Please define all of the cost drivers that were included in the average 1.9% price increase, and which drivers were not included. For instance, the page notes that items such as accounting policies which can drive rate impacts are "too technical" for the workbook.

b) Were participants ever provided with disaggregated or updated data about rate increases? For instance, the workbook includes at page 247 a chart demonstrating a 1.9, 1.3 and 1.4 percent increases. However, as outlined on Exhibit 1, Tab 3, Schedule 1, p. 5 of 26, some rate zones will see a much more significant increase, such as the 8% increase to Rate M1.

c) Were participants ever provided with EGI's proposal for incentive ratemaking for the future years of the term, including its proposal to increase the rates by inflation, a negative productivity factor, no stretch factor, or an ICM mechanism?

d) Were participants ever provided any information regarding EGI's proposal to increase its equity thickness?

e) On page 330 of 550, please explain how the annual forecasted bill impacts for 2025 and onwards were calculated/forecast.

Response:

a) The following cost drivers were included in the average 1.9% price increase: 2024 revenue deficiency from cost of service, preliminary depreciation proposal, equity thickness proposal at 42%, and disposition of deferrals.

b) No. The Fuel Choices (including the proposals for Responsible Sourced Gas and Renewable Natural Gas), and the Rate Harmonization Choices (including the proposal for rate zone harmonization), were shown separately, but not included in the overall bill impact shown to customers in the customer engagement.

c) No.

d) No. However, its impact was included in the bill impacts and referenced as 'proposals through which Enbridge Gas manages business risk and how it calculates the depreciation of its assets'. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 247, 330 and 432.

e) The forecasted annual impact of Enbridge Gas's plan for the 2025 to 2028 years were calculated by the impact the price cap rate-setting mechanism would have on revenue and proposed DSM budget changes[1] at the time. The assumptions for the price cap mechanism included a 2% inflation factor and productivity of -1.36% for total escalation of 3.36%. The equity thickness proposal of 42% was included in the 2024 forecasted bill impacts.

[1] EB-2021-0002, 2022-2027 Natural Gas Demand Side Management Framework and plan Application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1, pp. 4-5, 13

Question(s):

At pages 4 and 5, EGI describes the complementary stakeholder engagement that it has conducted.

a) To the extent that it is not already part of the pre-filed materials, please provide the results of EGI's monthly surveys with general service customers and the periodic satisfaction studies for contract and transportation customers.

b) To the extent that it is not already part of the pre-filed materials, please provide the information from the Ombuds Office that is made available to relevant departments at EGI.

Response:

a) A link to the press release with the latest results (2022) of the annual Mastio Natural Gas Pipeline Customer Value / Loyalty Benchmarking Study is provided at response to Exhibit I.1.6-SEC-83.

Reports with results for the following monthly and daily surveys conducted with general customers are provided in the response at Exhibit 1.1.6-SEC-83, Attachment 1, page 1, and Voice of the Customer Program, page 27.

The customer engagement process for this Application (2021 to 2022) as well as a commercial end-use survey (2020 to 2021) and the Asset Management Plan customer engagement process (2019), were priority projects for the past several years. For markets with fewer customers, such as the business markets, these priority projects limited the availability of customer lists for other market research initiatives, and where possible already included satisfaction questions. To avoid "survey fatigue", Enbridge Gas limits the number of times a given customer is solicited for feedback.

b) Please see Attachment 1 for a sample of the information distributed internally by the Ombuds Office.

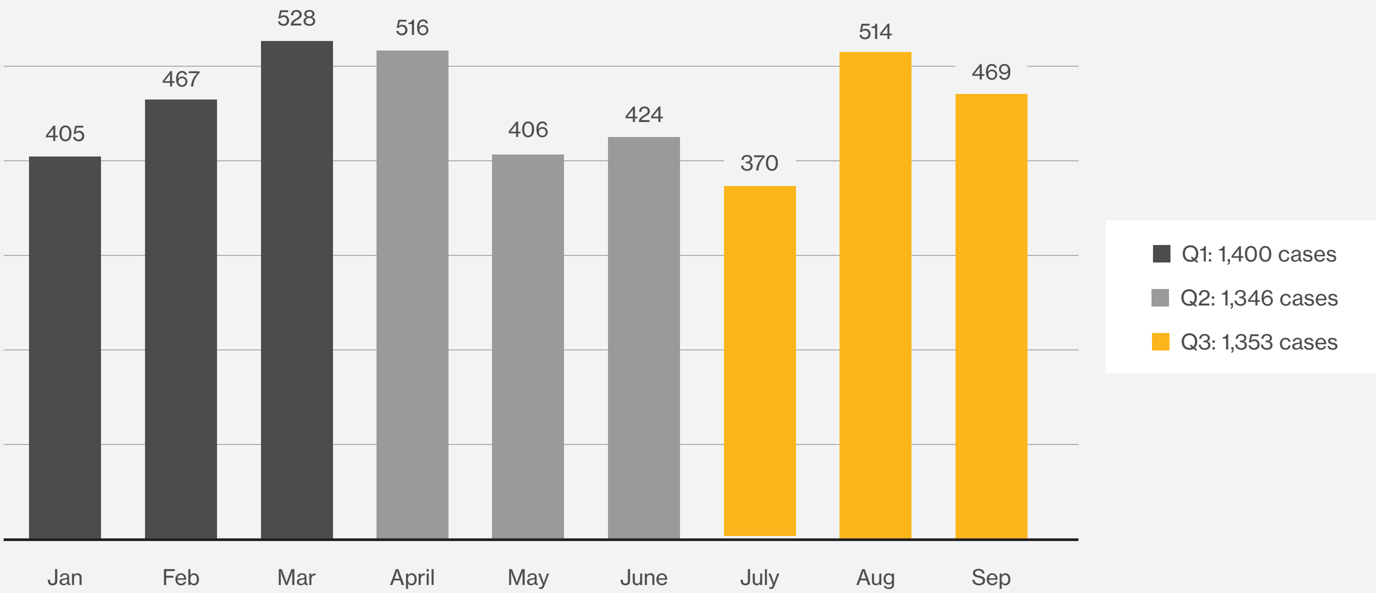
Ombuds 2022 Q3 Review

Public Affairs

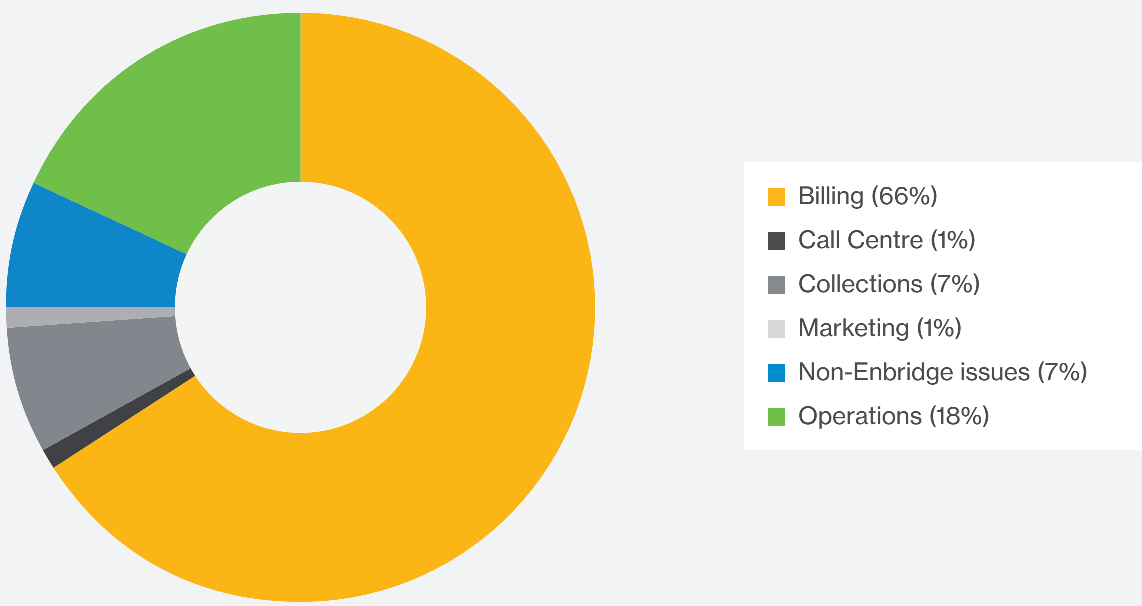
The number of monthly and quarterly cases forwarded to the Ombuds are shown below. Cases forwarded to the Ombuds in Q3 mainly concerned Billing (66%) and Operations (18%).

The Ombuds team saw an increase this quarter from customers receiving larger bills than expected. Higher rates increased both Equal Monthly Instalment Plan amounts and non-EMPP customer bill amounts. This is likely to continue as a trend while rates remain higher.

Cases: Q3



Top reasons for contacting us: Q3



ENBRIDGE
Life Takes Energy

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1, Attachment 1, p. 250 of 550

Question(s):

In the section "Making Choices", Innovative puts forward a description of compression stations, their function, and the replacement decision EGI is contemplating with respect to two compressor stations.

a) Did EGI ever attempt to quantify the risk of a compressor station failing if not replaced during this plan term?

b) If the answer to (a) is yes, please explain why that was not provided to respondents.

c) If the answer to (a) is no, please explain why not.

d) Did EGI ever attempt to determine the cost of a failure (with respect to having to purchase gas at market rates rather than draw from storage) in the same fashion as the cost of replacement (for example, as a $/year for the average customer) so as to provide an apples to apples comparison with the cost of replacement?

e) If the answer to (d) is yes, please explain why that was not provided to respondents.

f) If the answer to (d) is no, please explain why not.

g) Why was the question designed so as to only provide two substantive answers (complete it as planned or defer it as long as possible) with no other pacing alternatives available?

Response:

a) No. Please see Exhibit 2, Tab 6, Schedule 2, Appendix A, page 4 for the project justification. A business case for the project has not yet been completed. Enbridge Gas is currently undertaking an Asset Health Review as described at Exhibit 2, Tab 6, Schedule 2, page 183, paragraph 4. Included in that review will be a third-party

Reliability, Availability and Maintainability study to quantify risks associated with asset failures. This study will support detailed alternatives analysis and final scoping for the Dawn C Compression Lifecycle project which will in turn inform the project cost estimate and business case.

b) Please see part c).

c) While Enbridge Gas discussed this at the time of the customer engagement the risk and the potential costs are subject to different variables, including the time of year of failure, availability of alternatives, maintenance requirements, and market prices. This requires an extensive analysis that will be completed as described in part a).

d) Enbridge Gas was unable to determine the cost of failure as the potential costs would vary according to market conditions.

e) As described in the response to part c) the risk of failure and the potential cost is subject to different variables. The potential costs vary according to these factors and could have broader implications for the market price, which means that the potential costs may vary greatly. As a result, Enbridge Gas chose to focus on the risk to reliability and price volatility as described in the question text. As described in the introduction text about Making Choices, trade-offs are made between competing outcomes, and in some cases, these are not easily described as apples-to-apples comparisons.

f) Please see part e).

g) Enbridge Gas focused its question-and-answer choices on options that were feasible at the time of the draft plan, as described in Exhibit 1, Schedule 1, Tab 6, page 12.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1, Attachment 1, p. 253 of 550

Question(s):

In the section “Making Choices” Innovative puts forward a description of vintage steel pipes, the program to replace them, and the possible options for how to approach the program.

a) Did EGI ever attempt to quantify or forecast the future costs or the increases resulting from the “delayed approach”?

b) If the answer to (a) is yes, please explain why that was not provided to respondents.

c) If the answer to (a) is no, please explain why not.

Response:

a) No.

b) Please see part c).

c) The increased risk of leaks of a reactive stance, or the “delayed approach”, will require additional internal as well as external resource overheads and costs, which are subject to the varying cost pressures applicable at the time. While Enbridge Gas looked at these different variables, since these cost drivers are subject to many different scenarios, these were not fully explored to include in its plans or in the customer engagement.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1, Attachment 1, p. 268 of 550

Question(s):

At page 268, the engagement report states that once all advanced meters are rolled out, rates will initially increase, then decrease to levels lower than today.

a) Please provide how EGI calculated the rate increases/decreases that it used in making that statement.

b) Please provide whether that calculation includes the cost to replace advanced meters, or whether the replacement will cause costs to escalate again.

Response:

a) Please see Table 1 for the bill impact calculations provided in the table at Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 268.

Table 1
Advanced Meter Infrastructure
Residential Customer Bill Impacts

Line No.	Particulars	Option 1	Option 2	Option 3
1	Capital Investment ($ millions) (1)	1,593	1,720	2,208
2	Years of Implementation	4	8	20
3	Year of Maximum Revenue Requirement	2028	2031	2026
	First Year Cost (2024)			
4	2024 Revenue Requirement ($000s)	12,701	8,458	5,450
5	2024 Number of Customers (2)	3,904,132	3,904,132	3,904,132
6	First Year Cost (2024) (3)	3.25	2.17	1.40
	Maximum Annual Cost			
7	Maximum Annual Revenue Requirement ($000s)	80,568	58,089	7,234
8	2024 Number of Customers (2)	3,904,132	3,904,132	3,904,132
9	Maximum Annual Cost (2024) (4)	20.64	14.88	1.85

Notes:
(1) The capital investment in advanced meters is incremental to the capital investment that would have been made on replacing existing meters.
(2) Forecast number of general service customers in 2024.
(3) Line 4 / Line 5 x 1000.
(4) Line 7 / Line 8 x 1000.

b) The revenue requirement used in the bill impact calculation for the maximum annual cost was prepared on the basis that the advanced meters would be replaced 20 years after initial installation.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 6, Schedule 1, Attachment 1, pg.263

Preamble:

Under the customer engagement segment for Making Choices – Cut off at Main, the evidence provides a response to the choice of ratepayers bearing the cost: *Enbridge Gas should charge the homeowner $750, and the remainder would be shared among all residential customers at an annual cost of $0.25 in 2024 increasing to $1.23 in 2028 for all projected cut-offs.*

Question(s):

What factors contribute to the 5 times increase in costs for this activity in a five year period?

a) What assumptions generate that forecast of cost escalation?

Response:

The cut off at main cost is a capital activity and therefore, the annual bill impact included in the customer engagement workbook was increased consistent with the incremental rate base added each year. For purposes of the customer engagement process, Enbridge Gas prepared the bill impacts of each customer choice based on the specific cost of each proposal and independent of the rate setting mechanism for future years. The actual annual impact to customers from 2025 to 2028 will be determined by the proposed incentive rate-setting mechanism and not the specific cost of each proposal.

a) As noted above, the bill impact is not increasing due to cost escalation but due to the notional incremental rate base added each year for cut offs at main. Note that Enbridge Gas is proposing to eliminate the cut off at main charge as provided at Exhibit 8, Schedule 3, Tab 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 6, Schedule 1, Attachment 1, pg. 41-42 & Tab 3, Schedule 1, Attach. 1

Preamble:

We would like to understand more about the Related Party Transactions.

Question(s):

For each year since 2015, for each of Tidal Energy Marketing Inc & US LLC, please provide the operating revenues and Gas commodity and distribution costs transferred between EGI and those companies.

a) Please provide the forecast for 2023 and 2024.

b) Please provide any transactions that were sole-sourced to Tidal including purchases, assignments or other commercial transactions.

Response:

Please see Attachment 1 which contains the historical and forecast activity between Tidal and Enbridge Gas from 2015 to 2024. This does not include the sale of Enbridge Gas unregulated storage to Tidal. Enbridge Gas believes these transactions are outside the scope of this proceeding.

a) Please see above.

b) "Total EGI Revenue with Tidal" outlined in Attachment 1 contains transactions negotiated directly with Tidal and transactions awarded as a result of competitive bidding processes through Requests for Proposals (RFPs) or open seasons. Transactions included in the revenue total includes short-term storage, long-term transportation, short-term transportation, short-term exchanges and name change fees.

"Total EGI Costs with Tidal" outlined in Attachment 1 include the cost of gas commodity and the cost of market-based storage purchased from Tidal to meet the needs of Enbridge Gas's Gas Supply Plan. All gas purchased from Tidal was completed within a competitive RFP whereby bids were awarded based on lowest price for volumes purchased. All market-based storage services purchased from Tidal was completed within Enbridge Gas's blind storage RFP process.

Historical EGI Revenues & Costs with Tidal

Line No.	Particulars ($ millions)	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast	Total	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	Tidal Energy Marketing US	-	-	-	-	-	-	-	-	-	-	-	
2	Tidal Energy Marketing Inc.	-	0.1	2.7	4.3	6.0	7.1	9.5	11.6	-	-	41.2	
3	Total EGI Revenue with Tidal	-	0.1	2.7	4.3	6.0	7.1	9.5	11.6	-	-	41.2	
4	Tidal Energy Marketing US	22.7	25.4	60.0	68.0	37.3	17.5	30.7	8.2	-	-	269.8	/u
5	Tidal Energy Marketing Inc.	23.3	17.7	38.3	76.0	30.0	13.2	16.4	22.1	2.9	0.2	240.2	/u
6	Total EGI Costs with Tidal	46.0	43.2	98.3	144.0	67.2	30.7	47.1	30.3	2.9	0.2	510.1	/u

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 6, Schedule 1, Attachment 1, pg. 41-42 & Tab 3, Schedule 1, Attach. 1

Preamble:

We would like to understand more about the Related Party Transactions.

Question(s):

Please provide each of the actual capital and operating expenditures to Lakeside Performance Gas Services from 2015 to 2022 and the forecasts for 2023 & 2024.

a) Please provide actual capital and operating expenditures to all other companies who provide meters and meter services for those same periods.

b) How does EGI assess prevailing market prices?

Response:

Please see Table 1 for actuals from 2015 to 2022. The costs in Table 1 include emergency response costs as well as meter services costs. Enbridge Gas does not specifically budget by vendor and therefore the estimates for 2023 and 2024 are the 2022 actuals carried forward.

Table 1
Lakeside Performance Gas Services Historicals

Particulars ($millions)	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
O&M	26.1	24.4	17.1	17.8	17.5	19.8	19.4	21.9	21.9	21.9
Capital	15.9	19.9	24.1	25.3	26.3	24.1	31.7	43.9	43.9	43.9

a) Enbridge Gas does not have contracts with other companies that do similar work to Lakeside Performance Gas Services (meter work and emergency response).

b) Enbridge Gas assesses market prices by leveraging the competitive bid process through a Request for Proposal or Request for Quote based on the value and scope of work, contract term and resourcing needs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 6, Schedule 1, Attachment 1, pg. 41-42 & Tab 3, Schedule 1, Attach. 1

Preamble:

We would like to understand more about the Related Party Transactions.

Question(s):

Please provide each of the actual capital and operating expenditures to Ontario Exavac from 2015 to 2022 and the forecasts for 2023 & 2024.

a) Please provide actual capital and operating expenditures to all other companies who provide meters and meter services for those same periods.

b) How does EGI assess prevailing market prices?

Response:

a) Please see Table 1 for actuals from 2015 to 2022. Enbridge Gas does not specifically budget by vendor and therefore the estimates for 2023 and 2024 are the 2022 actuals carried forward. To clarify, Ontario Excavac does not provide meter services and instead provides hydrovac services. Enbridge Gas currently has contracts with several hydrovac service providers apart from Ontario Excavac including Badger Daylighting Ltd., Bob Robinson & Son Construction Ltd., Drain-All Ltd.and , Supersucker Hydro-vac Service Inc.

Table 1

Summary of Vendor Spend

Line No.	Particulars ($millions)	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Ontario Excavac Inc.										
1	O&M	3.4	3.0	3.9	4.9	5.4	6.3	6.9	8.8	8.8	8.8
2	Capital	7.2	6.9	9.9	10.3	11.4	8.0	10.4	13.8	13.8	13.8
	Badger Daylighting Ltd.										
3	O&M	0.2	0.5	0.8	0.9	1.7	1.2	1.5	1.7	1.7	1.7
4	Capital	0.0	0.4	1.2	1.2	1.3	1.9	1.3	0.9	0.9	0.9
	Supersucker Hydro-Vac Service Inc.										
5	O&M	0.2	0.2	0.4	0.4	0.8	0.7	0.6	0.5	0.5	0.5
6	Capital	0.7	0.7	1.3	1.8	1.5	1.5	1.9	0.7	0.7	0.7
	Bob Robinson & Son Construction Ltd.										
7	O&M	1.3	1.1	1.1	1.0	0.9	1.7	1.6	1.6	1.6	1.6
8	Capital	0.6	0.7	0.9	1.1	1.2	1.2	1.2	1.2	1.2	1.2
	Drain All Ltd.										
9	O&M	0.6	0.4	0.6	0.8	0.8	3.2	1.1	1.4	1.4	1.4
10	Capital	1.0	2.1	1.3	2.0	3.2	3.1	3.5	2.5	2.5	2.5

b) Enbridge Gas assesses market prices by leveraging the competitive bid process through a Request for Proposal or Request for Quote based on the value and scope of work.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ginoogaming First Nation (GFN)

Interrogatory

Reference:

Exhibit 1, Tab 6
Exhibit 1, Tab 6, Attachment 1

Preamble:

EGI states that it conducted “an extensive customer engagement process throughout 2021 and early 2022 in support of” the Application. In addition, EGI notes that the objective of its customer engagement was to “integrate customer feedback into the business planning process” as this would ensure that the Application “adequately reflects and is responsive to customer needs and preferences.”

EGI retained Innovative Research Group (“**Innovative**”) to help design, execute, and document the results of EGI’s customer engagement. Phase of EGI’s customer engagement “focused on identifying customers’ perceptions of the key issues they would like the [EGI] rate application to address.” Customer feedback and key findings were provided to EGI’s planners to provide initial customer input into the development of draft investment plans.

Question(s):

a) Please file any and all reports, presentations, analysis, data, or other materials related to EGI’s engagement with First Nations in support of the Application.

b) Please provide a copy of all written instructions provided by EGI in relation to its customer engagement for the Application and Innovative’s report provided in Exhibit 1, Tab 6, Attachment 1.

c) Please provide a detailed outline of EGI’s First Nations consultation process with respect to the Application. Please include a description of all steps that EGI has taken or will take in order to engage, consult, and accommodate First Nations affected by the Application.

d) Please provide any and all notes from the customer engagement relating to First Nations that are supplementary to the report provided in Exhibit 1, Schedule 6, Attachments 1 and 2.

e) Please provide specific examples of how the Application was informed by the concerns and views of the members of affected First Nations, including GFN's members.

Response:

a) All customer engagement reports and analyses conducted are included within the Application. The customer engagement for this Application was completed with Enbridge Gas ratepayers including First Nations customers as provided in response at Exhibit I.1.6-Three Fires-1 part f). No additional reports, presentation, analysis, data or other materials related to this customer engagement with First Nations are available.

b) Enbridge Gas provided an initial set of written instructions to potential vendors in the Request for Quote bid package, which included the scope of work. The scope of the work was refined over the course of the project and the work executed by Innovative for each phase is provided in response at Exhibit I.1.2-CCC-3. Much of the instructions and decision making took place via meetings, however there were some written instructions (sent from Enbridge Gas to Innovative by email) regarding the scope for the three phases of customer engagement, as well as Innovative's report. These are provided in Attachment 1, and the original draft scope of work is provided in Attachment 2.

c) First Nations were included in the customer engagement conducted described in evidence and all steps related to the different phases are provided at Exhibit 1, Schedule 6, Tab 1, pages 2-14. Enbridge Gas has plans to communicate the decision to customers, the general public, and specific Indigenous communities in the franchise area.

d) Please see response at part a). There are no supplementary notes available.

e) Please see response at part a). The concerns and views of affected First Nations members are combined with the views of all customers who participated in the customer engagement, and examples of how the Application was informed by these concerns and views are provided at Exhibit 1, Schedule 6, Tab 1, p. 24.

From: GD Procurement <GDProcurement@enbridge.com>
Sent: Friday, March 12, 2021 2:41 PM
To: GD Procurement <GDProcurement@enbridge.com>
Subject: Enbridge Gas Inc. Invitation To RFQ No. 2021-02-26_Rate Rebasing Customer Engagement

Dear Proponents,

Enbridge Gas Inc. invites your company to submit a quote for the 2024 Rate Rebasing Customer Engagement initiative. The RFQ bid package and other pertinent documents are attached.

Please take note of the following;

- Deadline for Intent to Respond Form: March 18, 2021 at 3:00PM Eastern Time
- Question Submission Deadline: March 25, 2021 at 3:00PM Eastern Time
    - Send all questions regarding this RFQ to gdprocurement@enbridge.com
- Quote Submission Deadline: April 16, 2021 at 3:00PM Eastern Time
- Deadline to submit the Third Party Cybersecurity Questionnaire: April 23, 2021 at 3:00PM Eastern Time
- Please review the Consulting Agreement included in the RFQ and return it with your quote with your mark ups if any.
- Please do not contact any other Enbridge team member regarding this RFQ other than the RFQ Contact identified in the document.

Please acknowledge this email upon receipt.

I look forward to receiving and reviewing your submissions.

Regards,

Paul Arevalo
Advisor, Sourcing Services
Supply Chain Management
Gas Distribution and Storage

ENBRIDGE
TEL: 416-495-5996 / CELL: 416-725-6297
500 Consumers Road North York, Ontario M2J 1P8

enbridge.com
Safety.Integrity.Respect.

ATTACHMENT: "RFQ No. 2021-02-26_2024 Rate Rebasing Customer Engagement.pdf", "Appendix C-Commercial Requirements.xlsx", and "Third Party Cybersecurity Questionnaire.xlsx"

Excerpt from Attachment with Scope of Work is in Attachment 2.

From: Gesiena Antuma <Gesiena.Antuma@enbridge.com>
Sent: May 28, 2021 3:16 PM
To: Susan Oakes <soakes@innovativeresearch.ca>; Greg Lyle <glyle@innovativeresearch.ca>; Julian Garas <jgaras@innovativeresearch.ca>
Cc: Asha Patel <Asha.Patel@enbridge.com>; Karen Sweet <Karen.Sweet@enbridge.com>
Subject: RE: FOR YOUR REVIEW: Phase 1 Discussion Guide draft

Hi Susan,

We would guide our decisions around this by what is preferred by customers, what will stand up from a methodological perspective, what is efficient, and cost-effective.

So I think that with that in mind …

- We would be open to an online recruit
- To make sure we offer an opportunity for the 40% without email addresses to participate we should still prefer to do some phone recruits – do you typically do that?
- We haven't done this type of recruit, so we'll want to see a bit more about how that works so that we can decide where to send the emails from (we can use our marketresearch@enbridge.com inbox, I'll check to see if we can leverage our Qualtrics system as a way, or have you send them). For more typical online surveys our preference will be for us to send it, but don't know how it will be different or the same for this type of recruit. I'll also need to make sure we can line up resources, so I'll investigate this as well.

In our meeting we talked about 8 groups, but then I think we later talked about 10 groups, and we loosely talked about reducing our IDIs for the business customers to manage costs. The IDIs to perhaps 10 per legacy, but I am not sure if that would be for Small and Med/Large each or altogether. Budget-wise, we can be flexible within the phases, and across the phases, but we will keep close tabs on the whole engagement altogether, so any ballparks around this would be helpful.

For honorariums, particularly for residential, we typically offer $100 for 90 minutes, though those were mostly in-person. Once these are decided on we'll make sure that we share all of this with the contact centre so that any concerns with the legitimacy of the research (which usually increase when there is $ involved) can be addressed easily. For this, please also send us any call display details for your organization, if any.

Thanks!

Gesiena Antuma
Customer & Market Insights

—

ENBRIDGE GAS

From: Gesiena Antuma
Sent: Wednesday, June 2, 2021 4:58 PM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>
Subject: RE: Change to Residential Focus Groups

Thank you Susan.

We can understand that having two groups in each area would be useful as you indicate below and so we will propose 2 groups in each of the identified region (I am renaming them a little to make them match our data) with good representation from all the various usage and demographic details. We see that this would get us a good mix of customers, a variety of views, and will also make recruitment a little simpler/easier.

If you can put Karen's name on the SOW, it will match the contract. If you could also remove the signature requirement, then we'll give you an okay by email.

Group	Region	Number
LUG North	Northern	2
LUG Central / East	Hamilton/Halton, Eastern	2
LUG South / West	Windsor/Chatham, London/Sarnia, Waterloo/Brantford	2
LEG GTA	Toronto (1), Central West (21) Central East (45 and 35)	2
LEG Other	Eastern (65), Niagara (76) Central West (53), Central East (47)	2

Happy to discuss further if you think it is needed on this piece.

Gesiena Antuma
Customer & Market Insights

ENBRIDGE GAS

From: Gesiena Antuma
Sent: Tuesday, June 8, 2021 11:36 AM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Subject: RE: Customer Engagement - Phase 1 Sample loaded to FTP site

We would tend to include them *[edit: Manitoba area codes]*. Similarly, we would include tenants, even though they may not have the same opportunity to consider fuel switching as a homeowner would, they are still customers. We would be more concerned about home ownership when we do research on our DSM programs, whereas in this case we would be more concerned about justifying any exclusions.

I think the only ones we might exclude are records with US phone numbers, simply because it may be an added challenge for participating and/or residents would have had challenges accessing the property ever since the border restrictions. We don't tend to check phone numbers for this.

Gesiena Antuma
Customer & Market Insights

ENBRIDGE GAS

From: Gesiena Antuma
Sent: Thursday, June 24, 2021 7:07 PM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Cc: Greg Lyle <glyle@innovativeresearch.ca>; Karen Sweet <Karen.Sweet@enbridge.com>
Subject: RE: Phase Two

Hi Susan,

Please find attached some specifications for Phase 2 to help in the development of the SOW. I am sure I have missed some details, so just let me know where that's the case. I think for C/I we may need to have some flexibility built-in to how to cost for this, because we would like to combine telephone and online results depending on the success with online. This has been our approach with this market. We do have a survey running concurrently, which offers a $15 incentive, and though I don't think we should necessarily do that, I think it would be good to get the cost associated with that in case we decide to do that (don't think we'll know for sure before the 30th). Our survey will be intended to be shorter than that one, so that could be our reason for not offering it 😊

If the SOW could split out the costs by methodology where it makes sense, and for the report separately from the data collection that would helpful for us.

Not sure how the scheduling for IDIs is going, but if you have a sense of when the Phase 1 report will be available, that will be good to know for us to plan the dissemination of that.

I am might online only sporadically tomorrow but will try to get back to you as fast as I can if you have any questions.

Gesiena Antuma
Customer & Market Insights

—

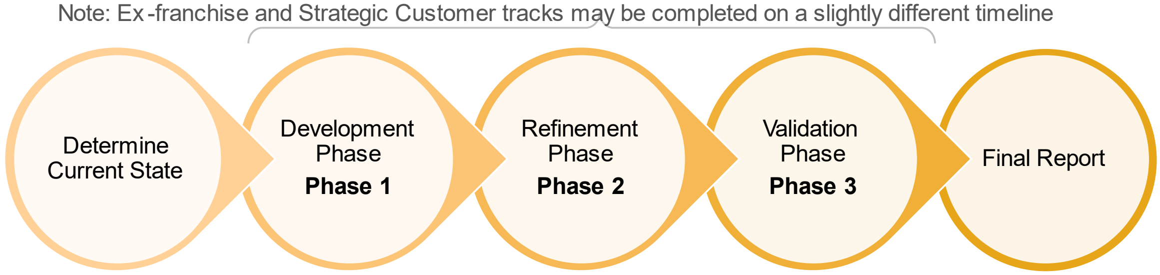
ENBRIDGE GAS

ATTACHMENT 2024 Rate Rebasing - Customer Engagement - Specifications for Phase 2.pptx of 5 slides is shown here:

Customer Engagement Schedule

ENBRIDGE

Timelines to align with Rebasing Process and Customer Meetings
Note: Ex-franchise and Strategic Customer tracks may be completed on a slightly different timeline

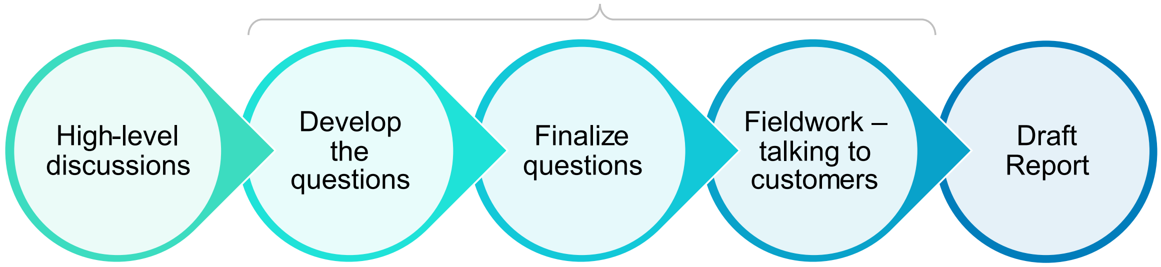


Determine Current State	Development Phase (Phase 1)	Refinement Phase (Phase 2)	Validation Phase (Phase 3)	Final Report
• Issue list review – considering major strategic issues first • Review other topics	• Develop discussion guide • Complete focus groups and in-depth interviews • Review results	• Develop questionnaires (by end of July) • Complete interviews (August) • Review results	• Develop questionnaires / workbook (including some testing) • Complete fieldwork • Review results	• Prepare draft report • Prepare 'Outcomes' Report
By Apr 30	May – Jun	Jul – Aug	Sep – Oct	By Dec 17, 2021

Refinement (Phase 2) –Timelines

ENBRIDGE

Timelines and Approach to be Finalized after Discussions with Stakeholders



High-level discussions	Develop the questions	Finalize questions	Fieldwork – talking to customers	Draft Report
•With various stakeholders •Brainstorm issues to review with customers •Decide whether these issues should be included in this phase or a future phase	•Developed by CM&I and vendor •Will require input from stakeholders	•Approval from various stakeholders (use existing meetings where possible)	•Completed by the vendor	
Ongoing	July 5-15	July 16-28	Aug 2 - 20	End of August

Focus to move up as possible

Residential Customers

Tentative options from Scope

ENBRIDGE

- All residential customers across rate zones – ensure some representation by rate zones and regions, as well as demographic indicators, including low -income customers (defined by survey)
- Telephone survey may have some different questions from the online if necessary
- Target a 15-minute survey, 1 main open-end

Phase	Comments (numbers are approximate):
Development	10 Online Focus Groups by Region (LUG North/East, LUG Central, LUG South/West, LEG GTA, LEG Other)
Refinement	Online – 2400 interviews (may consider some quotas, but only by sample -driven specifications) Telephone – 600 interviews (random sample)
Validation	Approach to be finalized

Commercial / Industrial Billed Customers

Tentative options from Scope

ENBRIDGE

- Not account managed
- Intend to combine results from online and telephone questionnaires to allow for a sufficient base size (i.e. response rate is an issue) – will need to ensure that questionnaires are close to the same
- Target a 15-minute survey, 1 main open-end
- Include optional $15 incentive in the SOW (including any admin cost for that, so it may still be considered)

Phase	By Volume	Need to review numbers and sample availability
Development	Small and Medium-Large	In-depth Interviews by telephone - 20 interviews (10 per legacy)
Refinement	Small	200 interviews, first by email, supplement with telephone Only as sample allows, with frequent check-ins
	Medium-Large	200 interviews, first by email, supplement with telephone Only as sample allows, with frequent check-ins (note: the 8814 records for LUG are all that are available for all phases)
Validation	Small	Approach to be finalized
	Medium-Large	Approach to be finalized

Large Volume and Strategic Customers

Developed in consultation with the Customer Care group

- Account managed customers (and energy marketers)
- Phase 1 work already completed and focused on service and rate harmonization and included meetings with 22 customers
- Webinar to present some service harmonization options with follow -up request for comments (this follow-up request for comments would include other engagement items) will be conducted by Enbridge Gas

Phase	Comments (numbers are approximate):
Refinement	**No refinement phase.**
Validation	Online – invitation to participate sent to all (assume n=100)

From: Gesiena Antuma
Sent: Monday, August 9, 2021 2:21 PM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>
Subject: RE: Suggestion for Commercial Customer Incentives

Thanks Susan.

My apologies, between losing power and meetings I haven't had a chance to respond yet.

We're good with the Commercial survey edits that we sent last Friday. Please let us know how the revised survey lengths are.

For the incentive levels, we have mixed experiences with the incentive levels, and appreciate your recommendation below. We're okay with offering a draw of multiple offerings of $500 as indicated below. It could be administered across Small / Medium / Large. Not sure if there is a specific number that draws attention in your experience, but with our limited sample size it would not have to be very many.

Gesiena Antuma
Customer & Market Insights
—
ENBRIDGE GAS

From: Gesiena Antuma
Sent: Friday, August 13, 2021 12:56 PM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>
Subject: RE: Update on Online Surveys

Thanks for the update Susan.

On the reminders, we can send reminders next week. Please give us a list of those you would like us to send reminders to as close as possible to the time we need to send them. We'll dedupe that against our DNC list and our list of other email responses.

I got a lot of automatic replies of business contacts out of the office until Monday, so we may see some more come in early next week because of that.

I've also uploaded one more link reset. It might be a complete, but if you can check I can respond to this customer.

On the reporting, I couldn't get a meeting set-up to talk about it with our team until Monday morning.

Based on your proposal I do have a question about combining the telephone and online results for Residential. It was my understanding that we would be comparing those results, so I am not sure if that is something you are doing on your side separate from the report, and combining them for the final report, or that we would also need to show the results side-by-side in the report as well.

For the Commercial, we already separated Small and Med/Larg based on consumption, so I don't think that a further split by consumption will be needed. It might be more meaningful to look at the variables

BROAD_CLASSIFICATION **SECTOR_FOR_NEXT_GEN_EVAL**

but I also don't imagine we will have enough completed interviews to report by them.

For the summary report, I agree that we can use Small and Medium-Large combined, but at the same time, if the results vary significantly, and if the base sizes are big enough then would probably want to look at them separately.

Gesiena Antuma
Customer & Market Insights
—
ENBRIDGE GAS

From: Gesiena Antuma
Sent: Monday, August 16, 2021 11:40 AM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>; Greg Lyle <glyle@innovativeresearch.ca>
Subject: RE: Phase Two Reporting

Hi Susan,

The reporting suggestions provided look good to us, we've made some comments below.

Thanks,

Gesiena Antuma
Customer & Market Insights
—
ENBRIDGE GAS

From: Susan Oakes <soakes@innovativeresearch.ca>
Sent: Wednesday, August 11, 2021 12:01 PM
To: Gesiena Antuma <Gesiena.Antuma@enbridge.com>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>; Greg Lyle <glyle@innovativeresearch.ca>
Subject: [External] Phase Two Reporting

EXTERNAL: PLEASE PROCEED WITH CAUTION.
This e-mail has originated from outside of the organization. Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.

Hi Gesiena,

Now that the surveys are all up and running, we are going to start prepping the reports. I wanted to get your feedback on the segments we will include in each of the reports. Below are my thoughts.

Residential Report:

- Topline results (combined telephone and online where questions were asked via both methodologies) – are we intending on combining the phone and online data? Or would we also compare the results, or could we review that separately?
- Segments:
  - LEAP qualification (per OEB criteria, combining HH size and income)
  - Legacy
  - Legacy Union Gas – North (region LUG North/East) and South (all other LUG) – if sample size permits
  - Consumption (Low, Medium-Low, Medium-High, High)

Commercial Report:

- Topline results (combined telephone and online where questions were asked via both methodologies)
  - Broken down into small vs med-large business

- Where sample size permits, we will include the following segments (still keeping small separate from med/lg):
  - Legacy
  - Legacy Union Gas – North (region LUG North/East) and South (all other LUG)
  - Consider Broad Classification or Sector Next Gen Eval from the sample as sample allows
  - Consumption (below or above average) – since Small and Med/Larg were already based on consumption, we would not need this

We will also include a summary comparing residential and commercial customers. For this part of the analysis, do you want us to combine all commercial data, or do you want to keep small separate from med-large (or maybe we make that decision based on what our final sample sizes are for each group)? I agree that we can use Small and Medium-Large combined, but at the same time, if the results vary significantly, and if the base sizes are big enough then would probably want to look at them separately.

In an earlier conversation/email, you had indicated that region was not of interest to you for reporting purposes, but are there any other segments you would like to include in the residential report?
Happy to have a chat if you'd like!
Susan

From: Gesiena Antuma
Sent: Tuesday, September 21, 2021 10:38 AM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>; Greg Lyle <glyle@innovativeresearch.ca>
Subject: New Phase 3 timeline for your review

Hi Susan,

We're looking at our options for the new Phase 3 timelines. We need to start communicating this as soon as possible (the Regulatory team is in the midst of Evidence Guideline meetings with all the stakeholders groups so the date of the Customer Engagement input is key to them), so I'd like to get your confirmation on some of these dates, especially on top line reporting. If it feels right to you let us know (or if not!), we have a meeting at 1pm where we can communicate that, or otherwise we have meetings tomorrow where we would start communicating it. I think this somewhat reflects the discussion we had yesterday, so hopefully it sounds right, but let us know 😊

- Overall impacts being available on November 15 (we'll have some notional ideas beforehand), but this would likely affect all customer groups in the same way.
- Testing of the questions would take place late October/early November – ahead of having that Nov 15 rate impact (we would adjust to what we have at that time).
- We launch the representative sample as quickly as possible for residential customers and have a fieldwork period of about 2 weeks (from Phase 2 we know that that is possible, we may need some more sample for it since the survey is much longer) and report those results before we report everything else. This would get us some results in early December, rather than waiting until January. This is important because the December 17 timeline was connected to some other input and modeling requirements. **I've put December 10 below. This would be key for us, so I'd like to confirm that we could report fairly quickly after completing the online representative residential sample.**
  - If the verbatim coding needs to be provided separately that is possible for us.
  - We would resolve low response rates with more sample, and adjustments of total quota / weighting, and/or allowing a couple of extra days of fieldwork.
  - We can help develop the reporting template while still in field. We would use Phase 2 as a guide.
  - So far in Phase 2 we have seen that Residential and Small Business customers tend to provide similar feedback (similarly, Med/Large Business customers feedback has not been vastly different from Small Business customers).
  - I think you shared that in your experience the voluntary sample often has similar feedback to the representative sample. This would mean that the representative sample for residential would provide the bulk of the feedback for us, while at the same time we can start reviewing some preliminary results for business and voluntary sample depending on how fieldwork is going.

Does this seem right? Let me know what you think.

Phase 3 Customer Engagement - New Timeline (removed table)

From: Gesiena Antuma
Sent: Monday, October 4, 2021 11:25 AM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Cc: Greg Lyle <glyle@innovativeresearch.ca>; Karen Sweet <Karen.Sweet@enbridge.com>
Subject: RE: Phase Three Discussion

Hi Susan,

Please see my responses below.

Thanks!

Gesiena Antuma
Customer & Market Insights
—
ENBRIDGE GAS

From: Susan Oakes <soakes@innovativeresearch.ca>
Sent: Friday, October 1, 2021 11:20 AM
To: Gesiena Antuma <Gesiena.Antuma@enbridge.com>
Cc: Greg Lyle <glyle@innovativeresearch.ca>; Karen Sweet <Karen.Sweet@enbridge.com>
Subject: [External] RE: Phase Three Discussion

Hi Gesiena,

I'd like to confirm a couple of details in order to develop the budget for Phase 3. Here are my specific questions:

- Will the openlink version of the workbook be open to all general service customers or just residential? I think we should keep it open to all general service – there may small businesses that we capture through social media
- I have in my notes from some time ago that you have about 30 Transportation customers. Is that accurate? That's right. We may have some that are also Contract customers, in which case they'll do the Contract Workbook, as well as a small group of other customers (producers) that may be included here – there is about 4 or so of them. 30 is probably a good assumption.
- The other customer segment we haven't discussed is Strategic (Large Volume Commercial). What is the planned approach for that group of customers? Will there be an online workbook survey for them, or will you be contacting them internally and we will just do the short validation interviews with them? How many Strategic customers do you have – is it around 30 as well? About 30, we're anticipating including them with the Contract Customers using an Online Workbook.

Thank you!
Susan

From: Gesiena Antuma
Sent: Thursday, November 25, 2021 9:45 AM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>; Greg Lyle <glyle@innovativeresearch.ca>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>; Asha Patel <Asha.Patel@enbridge.com>
Subject: RE: Timing for testing

I am sold. I was working on the wording for the email invitations and had a similar thought. We received some complaints last phase from residential customers as well, so I think it would be good to add it.

Gesiena Antuma
Customer & Market Insights

ENBRIDGE GAS

From: Susan Oakes <soakes@innovativeresearch.ca>
Sent: Thursday, November 25, 2021 9:41 AM
To: Gesiena Antuma <Gesiena.Antuma@enbridge.com>; Greg Lyle <glyle@innovativeresearch.ca>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>; Asha Patel <Asha.Patel@enbridge.com>
Subject: [External] RE: Timing for testing

Hi Gesiena,

I know the original plan was to offer incentives only to commercial customers, but I think there is a strong argument for providing an incentive to residential customers as well.

1. We are trying to capture a lot of data in a short amount of time (Dec 6 and getting you preliminary data by Dec 17). We will likely get a lot more responses if there is an incentive in place
2. We have to be upfront about the length of the survey, and so we say on the first page that it will take 20-30 minutes to complete. This is a pretty big chunk of time, so it would be nice to follow up that statement with an incentive.
3. It doesn't need to have a big budgetary impact. We could offer 4 draws of $250.
4. Given that we changed our approach to the testing, which will reduce the budget for that, we can add the incentive without increasing the overall budget for Phase Three

Have I made a compelling enough case? 😊

Susan

From: Gesiena Antuma
Sent: Thursday, November 25, 2021 2:17 PM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>
Subject: Phase 3 some next steps

Hi Susan,

For the Wednesday and Thursday testing sessions, would those be sessions with opportunities for us to watch? If so, do you know what time they would be? I am trying to see if any of us might be able to listen in, so I wanted to check. With testing on Wednesday and Thursday, would you anticipate a review call on Thursday and/or Friday? And a launch on the Monday?

I am also thinking through what the next week or so after that look like, as I will be away from work December 2-10 (I am getting married during that time, so to say that everything is really busy right now is an understatement!) but I will be working with Karen to ensure that the rest of the research team can help with any changes to the workbooks and to execute on the fieldwork so that everything moves along. I'll be working on the inputs for that over the next couple of days, I'll list some items:

- Email invitations – see attached, not sure what the best date would be to put into the invitation, so that might need to be adjusted, or if you have other edits let me know.
- Residential representative completes – reduce down to 5400 (from 7200) which with 300 LEAP would still be very good to accommodate the timing. I think this might help for setting quotas, but similar to Phase 2 it may be better to keep the survey open even if a quota is full. If you need more sample for residential I do have some prepared that we could send ahead of time or as needed.
- Getting a link up and running via our website, as well as preparing our social media posts. I am not sure at what point you would know which link we would redirect to. We'll be redirecting to it from www.enbridgegas.com/haveyoursay. You can let me know what the timing for that in the process might be.
- I am also working on getting the business workbook prepared, though know that there may be some changes yet in the residential

I'll probably have some more items to add, and you may have some items to add too 😊

Gesiena Antuma
Sr. Advisor Customer & Market Insights

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enbridgegas.com
Safety. Integrity. Respect. Inclusion.

From: Gesiena Antuma
Sent: Tuesday, January 11, 2022 3:46 PM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Cc: 'Greg Lyle' <glyle@innovativeresearch.ca>; Karen Sweet <Karen.Sweet@enbridge.com>
Subject: Business Reporting Cuts

Hi Susan,

(I'm having some email issues just now, so I'll pre-apologize if you get this email as a reply to your email as well)

We would like to propose the following reporting cuts. I added some notes in the attached, but to summarize below:

Business Customers (note: not calling them commercial because we often distinguish between commercial and industrial and our results include industrial)

- Legacy:
    - LEG
    - LUG
- LUG Region:
    - LUG North (show East/ West only for the Rate Zone question)
    - LUG South
- Consumption:
    - Small (50,000 or less) – this is the majority of interviews
        - Four Quartiles
    - Med-Large (50,001 or more) – only 203 interviews so this is not enough as a segment on its own (suggestion to combine with all business customers as a whole segment and to report out by consumption)
- Sector (add a caveat somewhere in the report that this is based on database segments)
    - Agriculture and Greenhouse
    - Manufacturing
    - Multiresidential
    - Food Services
    - Office
    - Retail
    - Transportation and Warehouse
    - Other (combination of remainder, may not be useful, only to get us to a complete group for the remainder of the sample, it might help the interpretation of these results compared to total)
- Strain of impact of bill on overall finances (measure of vulnerability) – if this makes sense based on the numbers
    - Agree
    - Disagree

Let me know if you have any questions or suggestions about these or if there were any data points that end up looking worthwhile considering.

Thanks!

Gesiena Antuma
Sr. Advisor Customer & Market Insights
—
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TEL: 519-436-5296
gesiena.antuma@enbridge.com
50 Keil Drive North, Chatham, ON N7M 5M1
enbridgegas.com
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Attachment: EGI.01 Potential Commercial Segment for Analysis - Business Segments DRAFT.xls removed

From: Gesiena Antuma
Sent: Tuesday, January 18, 2022 10:01 AM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>
Subject: Fuel Choices Report based on Phase 3 Residential and Business

Hi Susan,

I think we only briefly talked about this a while ago … one thing that we would like to do is to take some of the results from the residential and business reports to make a Fuel Choices report covering the RSG and RNG results from Phase 3 only. This is something we would like to include in our Gas Supply Plan which will be filed ahead of filing our Rate Rebasing application.

We would like to include the results from the Representative Residential and Business reports (I don't think the Voluntary results will be needed for this report). I've suggested through the attached report with comments and highlighting what we think we should include for fairly simple background information and results. We would want to add the Business results to this once available. Presumably in a fairly similar format as the Residential slides 69-75. I've included below some phrasing for the title page which I hadn't included in the attached:

Customer Engagement
Fuel Choices Report
General Service Customers

I am hoping it would be fairly easy to pull this report together from the completed Residential and Business reports. Would it be possible to send those reports also by the end of the week or early next week?

If it would help timing-wise I could also draft the reports from your PPT versions, if it is easier to share those, and have you review the final. Or let me know what you think would be best once you have had a chance to review.

Gesiena Antuma
Sr. Advisor Customer & Market Insights

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gesiena.antuma@enbridge.com
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enbridgegas.com
Safety. Integrity. Respect. Inclusion.

From: Gesiena Antuma
Sent: Friday, March 4, 2022 12:40 PM
To: 'Susan Oakes' <soakes@innovativeresearch.ca>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>
Subject: RE: Report Timing

Hi Susan,

Generally, we would not want to focus on the rate classes or the legacy utilities. Unless it is very applicable, such as with the rate zone question. We're focusing on being one utility, and as well, with the exception of the rate zone question did not distinguish impacts by these rate classes. So we can focus the results on the various customer segments, rather than rate classes (for example the business and contract segment is made up of many rate classes, so even there we'll want to generalize and look at them as segments) or rate zones.

Thanks,

Gesiena Antuma
Customer & Market Insights

ENBRIDGE GAS

From: Susan Oakes <soakes@innovativeresearch.ca>
Sent: Friday, March 4, 2022 11:19 AM
To: Gesiena Antuma <Gesiena.Antuma@enbridge.com>
Cc: Karen Sweet <Karen.Sweet@enbridge.com>
Subject: [External] RE: Report Timing

Quick question:

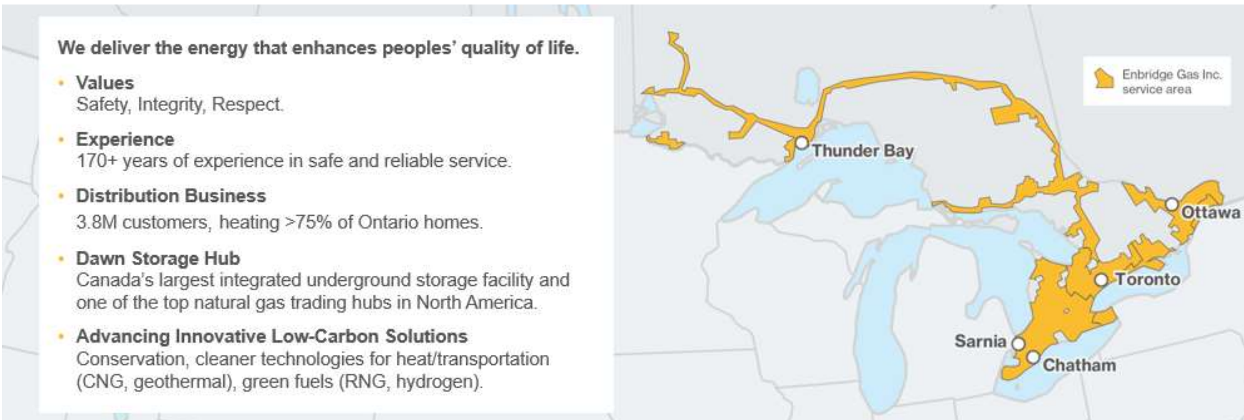
In the overall summary report, do you want us to compare only topline results across all rate classes, or would you like us to break it down into rate zones as well where possible?

Thank you!
Susan

APPENDIX F2
SCOPE OF WORK

Background

Enbridge Gas Inc. (EGI) is North America's largest natural gas storage, transmission and distribution company and serves customers across Ontario.



Enbridge Gas is planning to submit its 2024 Rate Rebasing and Next Generation IRM filing to the Ontario Energy Board (OEB) to establish new base rates and an incentive rate mechanism for the period of 2024-2028. Customer engagement has been identified as a critical activity to assist in supporting this submission. We know that the OEB wants a clear, customer-centric approach to be used to develop this filing, as better engagement of customers results in better planning, better consumer outcomes, as well as better utility performance.

The OEB's "consumer-centric" *Renewed Regulatory Framework for Electricity* (RRFE) shifts the focus from the utility costs to value created for customers. A key requirement of the Cost of Service rate application process includes documenting the active engagement between utilities and their customers. Utilities are required to demonstrate services are provided in a manner that responds to identified customer preferences and needs. Utilities must identify preferences and needs. Utilities must show how they took those needs and preferences into consideration.

The objective of this customer engagement is to build on previous customer engagement efforts that were conducted by Enbridge Gas Inc in 2019 and 2020, as well as by Legacy Union Gas (LUG) and Legacy Enbridge Gas Distribution (LEG) in 2017.

Therefore, Enbridge will need to:

- Identify or confirm customer needs and preferences
- Collect views on possible outcomes of interest to customers
- Identify decisions within the filing that have an impact on customers (on their rates, service levels, or other factors) and tie those decisions to desired customer outcomes

APPENDIX F2
SCOPE OF WORK

In past filings from other utilities regulated by the OEB, some key challenges and concerns expressed by the OEB include:

- Quality of approaches undertaken in previous applications
- Utility needs to ensure customer input is taken into consideration prior to development of application materials - ensure it is timely in formulating survey, conducting fieldwork, getting results and closing feedback loops
- OEB is critical of customer engagement that appears to reinforce utility's proposals rather than shaping it
- OEB is critical of lack of clarity over project specific & bill related information-utility should include asset specific info and the related impact for each item/project, avoiding mass grouping where possible
- Criticism received for vague/unclear relationship descriptions included in survey between capital spending and service quality – utility should be as specific as possible in outlining choices, i.e. what exactly constitutes service degradation as a result of lower incremental capital spending?
- Utility should provide additional information with respect to cost reliability trade-offs in addition to project-specific impacts
- Customer engagement should be timely and meaningful

Examples of Previous Customer Engagement Efforts for EGI

Filing EB-2018-0305: https://www.uniongas.com/-/media/about-us/regulatory/rate-cases/eb-2018-0305/EGDIUNIONEB20180305EXD20181214.pdf?la=en&hash=2C80B6B7180B20B3FA0FFE88A1DE76B4A337E7D5 (separate engagement efforts for LUG and LEG)

Filing EB-2020-0181: https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber%3DEB-2020-0181&sortBy=recRegisteredOn-&pageSize=400. Please review document EGI_APPL_Phase 2_20201015 listed as Application and Evidence, where pages 609-652 refer to the customer engagement completed to support the filing.

Timeline

All customer engagement work is to be conducted between May 2021 and December 2021. It is expected that the work will require several phases of research across customer groups.

Content of the Customer Engagement

The content and methodology of the Customer Engagement work will be driven by work done to identify issues. Various stakeholder groups will identify the issues that require customer feedback. For each of these issues the process of gathering feedback may vary, and as a result the customer engagement plan will require flexibility to be able to address this.

APPENDIX F2
SCOPE OF WORK

We anticipate that beyond these issues additional requirements for customer engagement include ensuring that customers understand the process and its implications and gathering feedback on general topics including, but not limited to, customer satisfaction, attitudes and preferences more generally.

Customers

Throughout the customer engagement process, it will be important to capture feedback from all of Enbridge Gas' customer groups. A brief summary of customer groups is provided below:

Customer Segments	Legacy Union Gas (LUG) Definition	Legacy Enbridge Gas (LEG) Definition	Comments (numbers are approximate):
Residential	M1 (South), R1 (North)	Rate 1	Customers who use less than 50,000 m3 of natural gas per year ~ estimated 3.3 million
General Service / Small Commercial	M1, R1, M2, R10	Rate 6 (Large Volume: 110, 115, 135, 145, 170, 200)	All Commercial / Industrial: Total Commercial: ~260,000 customers Total Industrial: ~21,000 customers Total Institutional: ~1,100 customers
Medium – Large Commercial / Industrial (Billed)			
Commercial / Industrial (Contract)	M4, M5, M7, T1, R20, R25		Commercial and industrial customers who have signed a contract for firm or interruptible gas delivery LUG: ~450 customers LEG: ~400 customers
Strategic (Large Volume Commercial)	M9, T2, T3, R100	To confirm	Largest users of natural gas in the wholesale (distributors of natural gas), chemical, refinery, steel, and power generation segments.
Transportation	M12, M12-X, Large C1	To confirm	Ex-Franchise Customers who contract for firm services to transport gas between any two interconnects

Potential Phases

1. Development
    - To develop an initial understanding of customer perceptions, opinions or beliefs and attitudes
    - This phase includes review of existing research and customer feedback and may be supplemented with additional customer engagement
2. Refinement
    - An initial evaluation of proposals and concepts to provide an opportunity to enhance and refine them
3. Validation
    - Provides follow-up opportunities to evaluate finalized proposals and concepts
4. Monitoring
    - Provides ongoing monitoring of attitudes and opinions towards proposals and concepts

The list of issues identified will help determine which phases will be necessary.

Methodology

For each phase, the yet-to-be determined list of issues and the unique set of customers that need to be engaged will drive the required methodology.

For the purpose of this quote, and based on previous customer engagement work, the Customer & Market Insights team recommends the methodologies outlined in this section for each of the phases.

Please make the following assumptions:

- All telephone or online interviews will be a maximum of 15 minutes in length, with maximum one open-ended question.
- Where customer lists are provided by Enbridge Gas the number of records will be sufficient to complete the required number of interviews, or fewer interviews will be required.
- All in-depth interviews will be conducted using telephone (or where possible using an online platform) and will be 45-60 minutes in length.
- Given the COVID-19 restrictions we will assume all meetings and interviews will be completed online / via telephone.
- Where possible, Enbridge Gas will provide pre-notifications to customers to help improve response rates. Among some of the Commercial/Industrial customers we may reach out to the same customers more than once across the phases of research.
- Enbridge Gas does not anticipate a need to provide incentives, though recommendations for incentives may be considered. *Please do not include in the cost worksheet.*

APPENDIX F2
SCOPE OF WORK

- Customer engagement will be conducted in English.
- Please assume that there will be no opportunity to use the Enbridge Gas website for the purpose of completing this customer engagement (due to a website integration project that will be ongoing throughout the term of the research).

For each of the phases, please provide a quote for the following options. Note that all will be considered optional and may be revised once the issue list is developed and the project becomes more defined in scope:

1. Development

While this phase is considered optional, please provide a quote in the event that any of these will be required.

Assume that this will take place in May and June 2021.

Customer Segments	Comments (numbers are approximate):
Residential	Online focus groups (bulletin board style – e.g. 3-day covering a variety of questions) – 2 groups with 20 customers per group; OR In-depth Interviews by telephone - 24 interviews (12 per legacy)
General Service / Small Commercial	Online focus groups (bulletin board style – e.g. 3-day covering a variety of questions) – 4 groups with 10 customers per group; OR In-depth Interviews by telephone - 24 interviews (12 per legacy)
Medium – Large Commercial / Industrial (Billed)	In-depth Interviews by telephone - 24 interviews (12 per legacy)
Commercial / Industrial (Contract)	N/A – internal efforts are already under way
Strategic (Large Volume Commercial)	N/A – internal efforts are already under way
Transportation	N/A – contact with these customers will be an internal effort

2. Refinement

During this phase we will focus on the key issues identified and refine the questions that we will intend to ask in the Validation phase.

Assume that this will take place in June to August 2021.

Customer Segments	Comments (numbers are approximate):

APPENDIX F2
SCOPE OF WORK

Residential	Online focus groups (bulletin board style – e.g. 3-day covering a variety of questions) – 2 groups with 20 customers per group; AND/OR Online – 600 interviews Telephone – 400 interviews
General Service / Small Commercial	Online focus groups (bulletin board style – e.g. 3-day covering a variety of questions) – 2 groups with 10 customers per group; AND/OR Online – 100 interviews Telephone – 50 interviews
Medium – Large Commercial / Industrial (Billed)	Online – 100 interviews Telephone – 50 interviews
Commercial / Industrial (Contract)	In-depth Interviews by telephone - 24 interviews (12 per legacy) with optional 1-hour stakeholder meeting to discuss the process and questions ahead of time
Strategic (Large Volume Commercial)	In-depth Interviews by telephone - 24 interviews (12 per legacy) with optional 1-hour stakeholder meeting to discuss the process and questions ahead of time
Transportation	N/A – contact with these customers will most likely be an internal effort

3. Validation

The bulk of the quantitative support will be gathered during this phase.

For each customer segment we may consider offering to host an optional 1-hour stakeholder meeting to discuss the process and questions to ensure.

Assume that this will take place September to November 2021.

Customer Segments	Comments (numbers are approximate):
Residential	Telephone – 1,800 interviews Online – 1,800 interviews; OR Consider an open link survey invitation shared via bill insert / myaccount
General Service / Small Commercial	Online – 400 Telephone – 400 (depending on online response)
Medium – Large Commercial / Industrial (Billed)	Online – invitation to participate sent to all (assume n=100) Telephone – 200 (depending on online response)

APPENDIX F2
SCOPE OF WORK

Commercial / Industrial (Contract)	Online – invitation to participate sent to all (assume n=100)
Strategic (Large Volume Commercial)	Online – invitation to participate sent to all (assume n=30)
Transportation	N/A – contact with these customers will most likely be an internal effort Consider set of validation interviews (5-10 min in length); OR Online – invitation to participate sent to all (assume n=30)

4. **Monitoring**

Not included at this time (may take place over the course of 2022).

Deliverables:

The research supplier will:

- Provide recommendations on the research methodology throughout the customer engagement process.
- Provide feedback and recommendations on the questionnaires developed by EGI's Customer & Market Insights team.
- Program and host all surveys and bulletin boards (if applicable).
- Complete the required interviews.
- Provide fielding data in the form of an SPSS data set, as well as detailed crosstabs in electronic form (coding for open-ended questions required).
- Provide top line and final reporting for each phase, as well as updates throughout the process.
- One final report covering the various phases of customer engagement.
- Support OEB proceedings, as required. Please note that the research supplier is not expected to act as a witness in the proceedings.

APPENDIX F2
SCOPE OF WORK

Quote Content Requirements:

The proposal should address the following:

1. Understanding of goals and objectives of the research.
2. Vendor recommendations on research methodology and targeted number of completed interviews.
3. Explanation of the Project Deliverables.
4. High-level timelines and milestones, including timelines for providing data and reports to EGI.
5. Cost estimates for each of the phases and the described elements of each phase, as described in this request for quote. In the quote, please provide a separate cost for each element of the deliverables.. The numbers used in this quote will be used to compare costs among applicants.
6. Identification of project liaison for day-to-day contact and other key personnel who will be working on the project.
7. Identification of related experience, including any experience working with clients in the utility and/or energy sector.
8. Identification of any potential conflict(s) of interest.
9. Confirmation of agreement with Enbridge Gas Inc.'s general terms and conditions.

Please note that the project award is subject to the successful completion of the TPRA (Third Party Risk Assessment). Please submit the Third Party Cybersecurity Questionnaire Spreadsheet by no later than April 23rd at 3:00 PM ET to gdprocurement@enbridge.com. Proponents that have gone through the TPRA process with Enbridge do not need to complete the Questionnaire.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Preamble:

In Exhibit 1, Tab 6, EGI reviews its customer engagement process undertaken in support of this application. In this evidence EGI describes meetings directly with contract customers. At paragraph 28 EGI discusses "*[p]reviously identified concerns related to customer engagement, such as the ability for customers to review the cumulative impact of their choices on overall rates*" and how those concerns were addressed. EGI also indicates elsewhere in its evidence that it has assessed the impact of its rate harmonization proposals on each of its large volume contract customers.

Question(s):

Please confirm that, as of the date of submission of these interrogatories, large volume industrial customers have not been provided with information on the specific impact of EGI's application proposals on their individual annual EGI bills.

Response:

Confirmed. Although the proposed rates are available at Exhibit 8, Tab 2, Schedule 7, Attachment 1 for customers to estimate their bill impact, specific customer impacts have not been provided.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association (QMA)

Interrogatory

Reference:

Ref: E1/T6/S1/p.4

Question(s):

Concerning customer engagement and ensuring a positive customer experience, reference is made to "…limiting the number of times the same customers were solicited for feedback…" Please identify the general geographic location within the Enbridge service territory where there are legacy Enbridge Gas Distribution Inc. and legacy Union Gas General Service business customers that are regularly surveyed by Enbridge.

Response:

Enbridge Gas surveys customers across its entire franchise area.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association (QMA)

Interrogatory

Reference:

Ref: E1/T6/S1/p.4-5

Question(s):

Enbridge states that it "…conducts daily and monthly surveys with randomly selected general service customers…". Please explain the survey process and types of surveys Enbridge uses to engage general service ("GS") business customers. How many GS business surveys would normally be conducted on a daily and monthly basis? Please provide a sample of a typical business customer survey.

Response:

General service (GS) business customers currently participate in three ongoing monthly and daily surveys:

a) Residential and Business Customer Experience Tracking was revised in January 2023 to include a random selection of general service residential and business customers. These surveys are completed monthly and include 50 GS business customers each month.
b) The Large Business Accounts Interaction survey is conducted daily and is an online survey with customers who contacted the Large Business Accounts department. The daily number of surveys ranges from 0 to 10, with an average of 40 per month.
c) The Chatbot Interaction survey is conducted daily with customers who connected with the online Chatbot. GS business customers comprise approximately 5-10% of the sample and are represented among a total average of 170 surveys per month.

The survey instrument for the "Large Business Accounts Interaction Survey" is provided as a sample of a post-transactional survey in Attachment 1.

In addition to these three ongoing surveys, Enbridge Gas conducts market research with GS customers on an ad-hoc basis. The customer engagement process for this Rebasing Application (2021 to 2022) as well as a commercial end-use survey (2020 to 2021) and the Asset Management Plan customer engagement process (2019), were priority projects for the past several years. For markets with fewer customers, such as the business markets, these priority projects limited the availability of customer lists for other market research initiatives, and where possible already included satisfaction questions. To avoid “survey fatigue”, Enbridge Gas limits the number of times a given customer is solicited for feedback.

Large Business Accounts Interaction Survey
Instrument as of February 21, 2023

Q1 Overall, how satisfied are you with your recent interaction with the Enbridge Gas Large Business Accounts Department?

- ○ 1 Completely Dissatisfied (1)
- ○ 2 (2)
- ○ 3 (3)
- ○ 4 (4)
- ○ 5 (5)
- ○ 6 (6)
- ○ 7 (7)
- ○ 8 (8)
- ○ 9 (9)
- ○ 10 Completely Satisfied (10)

Page Break

Q2 Overall, how satisfied are you with the Enbridge Gas Large Business Accounts customer service representative who handled your recent interaction?

- ◯ 1 Completely Dissatisfied (1)
- ◯ 2 (2)
- ◯ 3 (3)
- ◯ 4 (4)
- ◯ 5 (5)
- ◯ 6 (6)
- ◯ 7 (7)
- ◯ 8 (8)
- ◯ 9 (9)
- ◯ 10 Completely Satisfied (10)

Page Break

Q3 Please tell us what we did to earn this score.

____

____

____

____

____

Page Break

Q4 Once all of the required information was provided to the Enbridge Gas Large Business Accounts Department, did they resolve your inquiry?

- ○ Yes (1)
- ○ No (2)

Page Break

Q5 How many times did you have to contact the Large Business Accounts Department to resolve this particular inquiry?

- ○ Once (1)
- ○ Twice (2)
- ○ Three times (3)
- ○ Four or more times (4)

Display Question Q6:

If Once all of the required information was provided to the Enbridge Gas Large Business Accounts Dep... = No

Or How many times did you have to contact the Large Business Accounts Department to resolve this par... != Once

Q6 Can you tell us why?

____

____

____

____

____

Page Break

Q7 How would you rate your overall impression of Enbridge Gas as a company?

- ○ 1 Poor (1)
- ○ 2 (2)
- ○ 3 (3)
- ○ 4 (4)
- ○ 5 (5)
- ○ 6 (6)
- ○ 7 (7)
- ○ 8 (8)
- ○ 9 (9)
- ○ 10 Excellent (10)
- ○ Don't Know (11)

Page Break

Q8 What could we do to further improve your experience?

____

____

____

____

____

End of Block: Default Question Block

Start of Block: Block 1

Q9 We read all feedback we received. If needed, may we contact you?

- ○ Yes (1)
- ○ No (2)

End of Block: Block 1

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association (QMA)

Interrogatory

Reference:

Ref: E1/T6/S1/A1/p.9

Question(s):

During the course of customer engagement exercise undertaken by Innovative Research Group Inc. ("Innovative"), did customers have a good understanding and knowledge of what energy transition means? Was there a common definition of "energy transition" used with survey respondents and focus group participants? Was there a difference in the level of knowledge and understanding of energy transition between GS residential customers and GS business customers and was that difference significant?

Response:

In the customer engagement, the specific term "energy transition" was only used in some of the Phase One focus groups in a discussion exploring different customer outcomes. The phrase "facilitating the energy transition" was used to probe customer views related to the environment (if similar concepts were not already introduced by customers themselves). In a focus group or in-depth interview, the discussion is conversational in nature and participants can clarify their understanding with the facilitator or each other to ensure that there is a common understanding. The term was not used in any customer-facing elements of the subsequent phases, and only appears as a summary title in the reports prepared for report audiences.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association (QMA)

Interrogatory

Reference:

Ref: E1/T6/S1/A1/p27] and [E1/T6/S1/A1/p.276 (*chart*) and P.277 (*table*)

Question(s):

Please explain what is meant by “Social Permission” within the context of the customer engagement exercise; and the results shown on the chart and table referenced.

Response:

The following response was provided by Innovative Research Group:

As indicated in the first column of the bottom row of the table on pages 27 and 276 of Exhibit 1, Tab 6, Schedule 1, Attachment 1, and by the brackets in the chart on page 276, Social Permission is a label that applies to those who replied increase investments and those who replied maintain the draft increase. For example, on page 27, 71% of residential customers responded with at least maintain the draft increase.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association (QMA)

Interrogatory

Reference:

Ref: E1/T6/S1/A1/p.256

Question(s):

Regarding hydrogen gas and Enbridge's intent "… to launch a feasibility study that assesses the full system's readiness for more hydrogen to be included in the system." Please provide a table that shows the estimated annual cost for all the planned H2 study work that is expected to be allocated to GS business customers for the rate years 2024; 2025 and 2026; and 2027 and 2028.

Response:

Please see Exhibit 2, Tab 6, Schedule 2, page 75.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association (QMA)

Interrogatory

Reference:

Ref: E1/T6/S1/A1/p.310

Question(s):

Business customers were asked to agree or disagree with the statement that reads: “Customers are well served by the energy system in Ontario.” [QMA emphasis] where 79% of the surveyed respondents “agreed” with the statement. Was it made clear to the survey respondents what the “energy system” means? In other words, was it defined to mean natural gas only or could it have been interpreted to include electricity, natural gas, propane and oil? Please explain.

Response:

“Energy system” was not defined in the workbook. This question was presented to customers in the last section of the workbook (as part of the Respondent Profile section) for analytical purposes only. Questions in the Respondent Profile were included to provide options for segmenting and grouping similar people together when the survey results were analyzed. For this purpose, the question was designed to gauge high-level reactions, and therefore “energy system” was not defined. Please see response at Exhibit I.1.6-SEC-84, Attachment 1. The workbook page presented to general service business customers that contains this question can be found on page 82.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Quinte Manufacturers Association (QMA)

Interrogatory

Reference:

Ref: E1/T6/S1/A1/p.330 and p.432

Question(s):

The two charts concerning annual forecasted bill impacts (including the carbon charge) compared to current rates that appear on the referenced pages of Attachment 1 are almost identical. However, they are confusing. The statement below each chart reads: “These charges for business customers [QMA emphasis] may vary somewhat by rate class, and in all cases where we’re showing a rate impact, it is the highest potential impact across rate classes.” The asterisk on the page 330 chart for annual bill impacts notes the average customer consuming 2,400m3 NG/yr., which appears to be a reference to residential volumes rather than the average commercial customer discussed in the paragraph above the chart. There are no comparable gas consumption volumes shown for small and medium/large businesses for the chart on page 432. Please explain and clarify.

Response:

The footnote provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 330 that references an average customer consuming 2,400 m^3 of natural gas per year was erroneously included when the General Service Business Customer workbook page was added into the report. The version of the workbook that customers saw did not include this error. The business charts are not based on an annual consumption of 2,400 m^3, but rather on the average percentage impact for business customers of all consumption levels. As stated, the rate impacts shown are based on the highest potential impact across rate classes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-6-1

Question(s):

Excluding those undertaken for the purpose of DSM program design or community expansion customer attachment forecasts, please provide details of all other customer surveys and/or market research that Enbridge has undertaken since the amalgamation. Please provide copies of any such reports and/or analysis.

Response:

Customer surveys and market research studies are managed by the Customer and Market Insights (CMI) team at Enbridge Gas. Table 1 includes a list of studies that Enbridge Gas is attaching to this response, and where applicable, the most recent reports are provided in Attachment 1.

Table 2 includes a list of studies that were completed, for which no report is attached. The studies in Table 2 have been previously filed or were completed to support Enbridge Gas marketing efforts and included user testing. These studies helped to inform the design of specific customer-facing tools or communications, and while some details are shown here, these studies are not relevant to this Application and no reports are provided.

Enbridge Gas also conducts follow-up surveys with customers who attended specific in-person or webinar events to gather feedback and help improve future events. These surveys are not individually listed here.

Table 1
Customer Surveys and Market Research Studies completed since Amalgamation (Reports included)

	Study Name	Last Year Completed	Details
1	Residential Brand and Customer Experience Tracking	2022	Comprised of three surveys, this study measures overall customer satisfaction, satisfaction with the call centre and satisfaction with field work experience. The 2022 report is included in Attachment 1, p. 1.
2	Voice of Customer Program	2022	The Voice of Customer Program consists of nine online surveys that are sent out daily and measure satisfaction with Chatbot, Call Centre, Large Business Account interactions, Moves, Meter Exchange, Emergency, Billing, Communications, and Brand. Results are reported in an online dashboard that is accessible to Enbridge Gas employees responsible for these transactions/experiences. The 2022 summary report includes some high-level results and is included in Attachment 1, p. 27.
3	Mastio Transportation Customer Value/Loyalty Benchmarking Study	2022	Mastio is a benchmarking study of natural gas pipeline companies in North America and gauges pipeline customer satisfaction. It surveys all major interstate, intrastate, and Canadian pipelines across North America. The reports provided by Mastio are confidential, however a high-level summary of results is available as referenced in the response to Exhibit I.1.2-SEC-77.
4	Enbridge Brand Health Study	2022	Measures brand awareness and impression of Enbridge Gas and Enbridge Inc. The 2022 report is included in Attachment 1, p. 30.
5	Enbridge Gas Brand Pulse survey	2019	This study was conducted to measure awareness of the amalgamation among Legacy Union Gas customers. The report is included in Attachment 1, p. 99.
6	Natural Gas Safety Awareness and Compliance Survey	2022	Measures awareness of natural gas safety issues and related precautions/responses. The 2022 report is included in Attachment 1, p. 114. While this study contains some natural gas end use equipment figures, Enbridge Gas relies on the Residential Single Family Natural Gas End Use Study for these measurements.
7	Residential New Housing Natural Gas End Use Study	2022	Residential New Housing End Use Survey measures natural gas appliance penetration in new homes and experiences with the new build process. The 2022 report is included in Attachment 1, p. 161.
8	Residential Single Family Natural Gas End Use Study	2022	This study measures natural gas appliance penetration and preferences, insulation levels, and awareness of DSM. The 2018-2022 reports are provided at Exhibit I.1.10-GEC-7, Attachments 1 to 5.

Table 2
Customer Surveys and Market Research Studies completed since Amalgamation (Reports not included)

	Study Name	Last Year Completed	Details
1	Low Carbon Energy Project Customer Engagement	2019	This survey measures interest in Enbridge Gas' Low Carbon Energy Project, and was filed in EB-2019-0294, Exhibit B, Tab 1, Schedule 1, Attachment 5.
2	2019 EGI Asset Management Plan Customer Engagement	2019	Customer engagement for the 2019 Asset Management Plan was filed in EB-2020-0181, Exhibit C, Tab 3, Schedule 1, p.1 to 44.
3	Paperless Bill Incentive Quantitative Research	2019	This telephone survey was conducted to develop strategies to incentivize paper customers to move to paperless (electronic) billing (including incentives to use in marketing, i.e., donation, cash, bill credit).
4	EGI Paperless Bill Segmentation Research	2021	This telephone survey was conducted to create segments among paper billing customers to better understand them (and their likelihood to convert to paperless).
5	Driving eBill Adoption	2021	The primary objective of this online study was to better understand customer awareness and likelihood of using eBill features, principally the text/email reminder option, among those who have email, but are not signed up for paperless billing.
6	Bill Mitigation Messaging Research	2022	Using focus groups, this study was conducted to test messaging options with customers before launching a campaign about higher bills.
7	OptUp Form Testing	2021	Using in-depth interviews this study tested the OptUp Voluntary RNG program form on the website with customers to check for any concerns or usability issues (to help improve uptake of program).
8	Website Redesign project	2020	This study was done to help build the mainframe of the amalgamated website. It showed various options and allowed customers to share feedback on where they expect to find specific types of information.
9	Website Intercept Survey	2022	This intercept survey on the enbridgegas.com website was conducted to check satisfaction with the website and to identify any problem areas.
10	Canada Energy Regulator Public Awareness Campaign	2022	Multiple waves of online research were completed to confirm receipt of specific pipeline campaign materials for awareness of safety measures for those near a high-pressure pipeline.

Residential Brand & Customer Experience Tracker (R-BCX)

Enbridge Gas

2022 Year-End Report
Customer & Market Insights Team

About R-BCX

Launched in July 2019, the Residential Brand and Customer Experience Tracker (R-BCX) brought together two similar customer satisfaction measurement programs from Legacy Enbridge Gas Distribution (LEGD) and Legacy Union Gas (LUG). R-BCX has three separate sections or tracts, each with a different survey questionnaire and a different group of customers targeted.

Tract	Customers Targeted	Interviews per Month (#)	Margin of Error*		
			Monthly Results	Quarterly Results	Annual Results
Residential Overall	Randomly selected residential customers	200	+/- 6.9	+/- 4.0	+/- 2.0
Call Centre Experience	Customers who contacted the Call Centres in the previous month and connected to a live agent	200	+/- 6.9	+/- 4.0	+/- 2.0
Field Work Experience	Customers who had an at-home appointment for field work in the previous month.	200	+/- 6.9	+/- 4.0	+/- 2.0

*At the 95% confidence level for survey questions asked to all respondents.
Note: The margin of error is higher for questions only asked to a sub-set of respondents, such as customers enrolled in the online account management tools. The margin of error is also higher and for results broken down into smaller groupings such as results for individual legacy utility areas, regions, and call types. Please contact Market Research & Analysis to discuss accuracy prior to using results as an input to significant business decisions.

- 200 interviews are completed each month for each survey tract. 100 interviews are completed with customers in each legacy territory to allow separate analysis and reporting where necessary. Most of the results in this report are for the total Enbridge Gas area, with LUG results weighted at 40% and LEGD results weighted at 60% to reflect the actual split of residential accounts. Sample is provided to the vendor once a month, except for the Call Centre Experience tract, where sample is provided twice a month.
- R-BCX is administered by telephone by Leger, a Canadian market research vendor. All survey analysis and reporting is completed in-house by the Enbridge Customer & Market Insights team (part of the Marketing & Customer Insights group).

Interpreting the Results

ENBRIDGE

- The majority of the results found in this report are "Top 3 Box Scores". A Top 3 Box Score is the percentage of respondents who provided a rating of 8, 9, or 10 on a 10-point scale. Customers providing a Top 3 Box Score are highly satisfied.

Top 3 Box Score = ratings of 8, 9, or 10 on a 10-point scale

1 means "completely dissatisfied" and 10 means "completely satisfied".

1	2	3	4	5	6	7	8	9	10
	Bottom 3 Box Score			**Middle Box**				**Top 3 Box Score**	

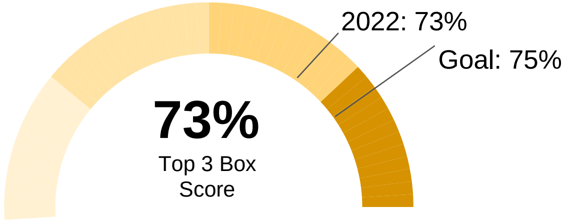
- Bottom 3 Box and Middle Box scores can also be of interest, as are mean scores. Please contact the Customer & Market Insights team to see results presented in a different way, or for any further analysis. Customized reports can be created on request.
- This report references a "2019 Baseline". The 2019 baseline reflects results from the July – December 2019 period (starting from the R-BCX launch in July to the end of the year).
- All R-BCX questionnaires currently refer to "Union Gas, currently operating as Enbridge Gas" or your "natural gas utility" instead of "Enbridge Gas" for Legacy Union Gas customers. This was deemed necessary (based on customer testing) to avoid customer confusion. This has an impact on the interpretation of results, particularly around the brand. Please contact the Market Research team for additional context and commentary.

Dashboard

ENBRIDGE

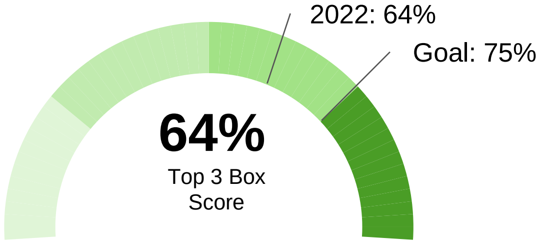
Overall Residential Customer Satisfaction at a Glance

Overall Satisfaction with Enbridge Gas	Top 3 Box Score	
	2021 *(Year-end)*	80%
	2022 *(Year-end)*	73% *



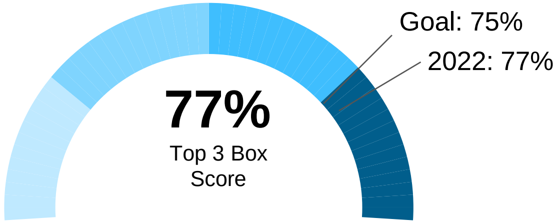
2022 Year-end			
Bottom 3 Box	Middle Box	Top 3 Box	Mean Score
2%	24%	73%	8.2

Overall Satisfaction with the Call Centre Experience	Top 3 Box Score	
	2021 *(Year-end)*	70%
	2022 *(Year-end)*	64% *



2022 Year-end			
Bottom 3 Box	Middle Box	Top 3 Box	Mean Score
11%	24%	64%	7.6

Overall Satisfaction with the Field Work Experience	Top 3 Box Score	
	2021 *(Year-end)*	79%
	2022 *(Year-end)*	77%



2022 Year-end			
Bottom 3 Box	Middle Box	Top 3 Box	Mean Score
7%	14%	77%	8.4

* Statistically significant movement compared to 2021 at 95% confidence level.

Section 1:

Enbridge Gas Residential Overall

- Overall satisfaction with Enbridge Gas
- Perceptions of the Enbridge brand
- Satisfaction with Enbridge Gas communications
- Satisfaction with the Enbridge Gas bill and the bill inserts
- Satisfaction with the website and the online account management tool

Enbridge Gas Residential Overall

2022 Year-End Spotlight

Overall customer satisfaction with Enbridge Gas, normally very stable, declined significantly in 2022. The decline is very strongly linked to natural gas prices and was most pronounced in Q4 2022 results - when colder weather and changes to Equal Monthly Payment Plan instalments made higher rates more evident on customer bills.

Dissatisfied customers also noted issues with customer service, meter reading (estimation and the accuracy of estimates), and communication (or a perceived lack of communication) related to rate increases.

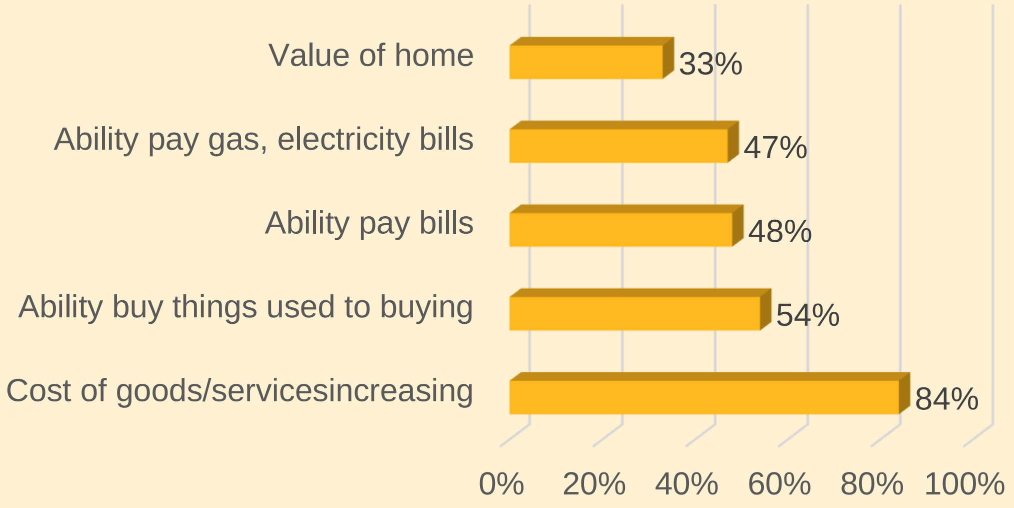
As seen in the past, higher bills drove lower ratings for most attributes of the Enbridge Gas bill, communications, and the brand. Significant declines in customer ratings are noted throughout this section of the report.

Ipsos' Inflation Tracker has found about one-half of Canadians are concerned about their ability to pay natural gas and electricity bills (June 2022 results)—important context for the interpretation of results.

Majority of Canadians are concerned with rising costs for goods and services, about one-half are concerned about their ability to pay gas and electricity bills

Thinking about your personal financial situation over the next six months, how concerned, if at all, are you about each of the following over the next six months?

(% 'Very'/'fairly concerned')



Source: Ipsos's June 2022 Inflation Tracker, n=1000

Enbridge Gas Residential Overall

Overall Satisfaction with Enbridge Gas

Overall Satisfaction with Enbridge Gas

"Based on your experiences or impressions and thinking about all aspects of their business, how would you rate your satisfaction with Enbridge Gas overall? Please use a scale from 1 to 10 where 1 means "completely dissatisfied" and 10 means "completely satisfied"."

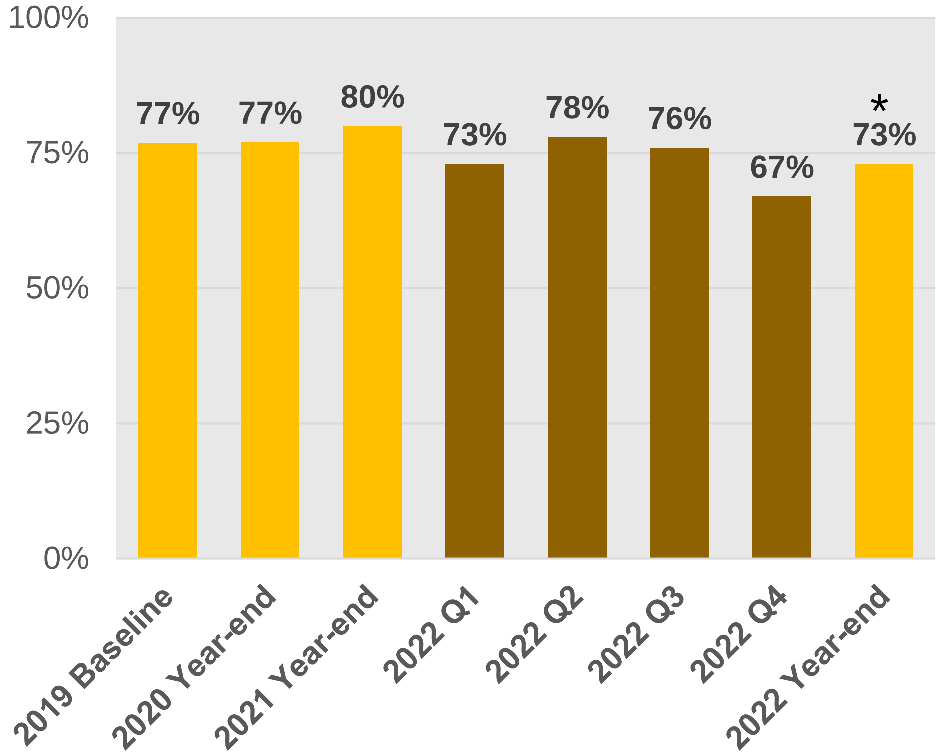
73%*

Top-3 Box Score (2022 Year-end)

Overall Satisfaction with Enbridge Gas

- "Overall Satisfaction with Enbridge Gas" is a summary for how customers feel about the utility. It encapsulates customer satisfaction across all of Enbridge Gas' interactions, transactions and communications.
- This score reflects ratings provided by randomly selected residential customers. Some of the customers surveyed experienced a recent transaction or interaction with Enbridge Gas, while others did not.

Overall Satisfaction with Enbridge Gas Historical Trend



** Significant movement compared to 2021 at the 95% confidence level.*

Enbridge Gas Residential Overall

Natural Gas Prices as a Driver of Satisfaction

Satisfaction with the price of natural gas is a key driver of Overall Customer Satisfaction and Overall Brand Impression.

While customers experience the same rate changes as other customers in their zone, perceptions of natural gas prices vary. Customers satisfied with natural gas prices tend to be satisfied with Enbridge, and the reverse is also true.

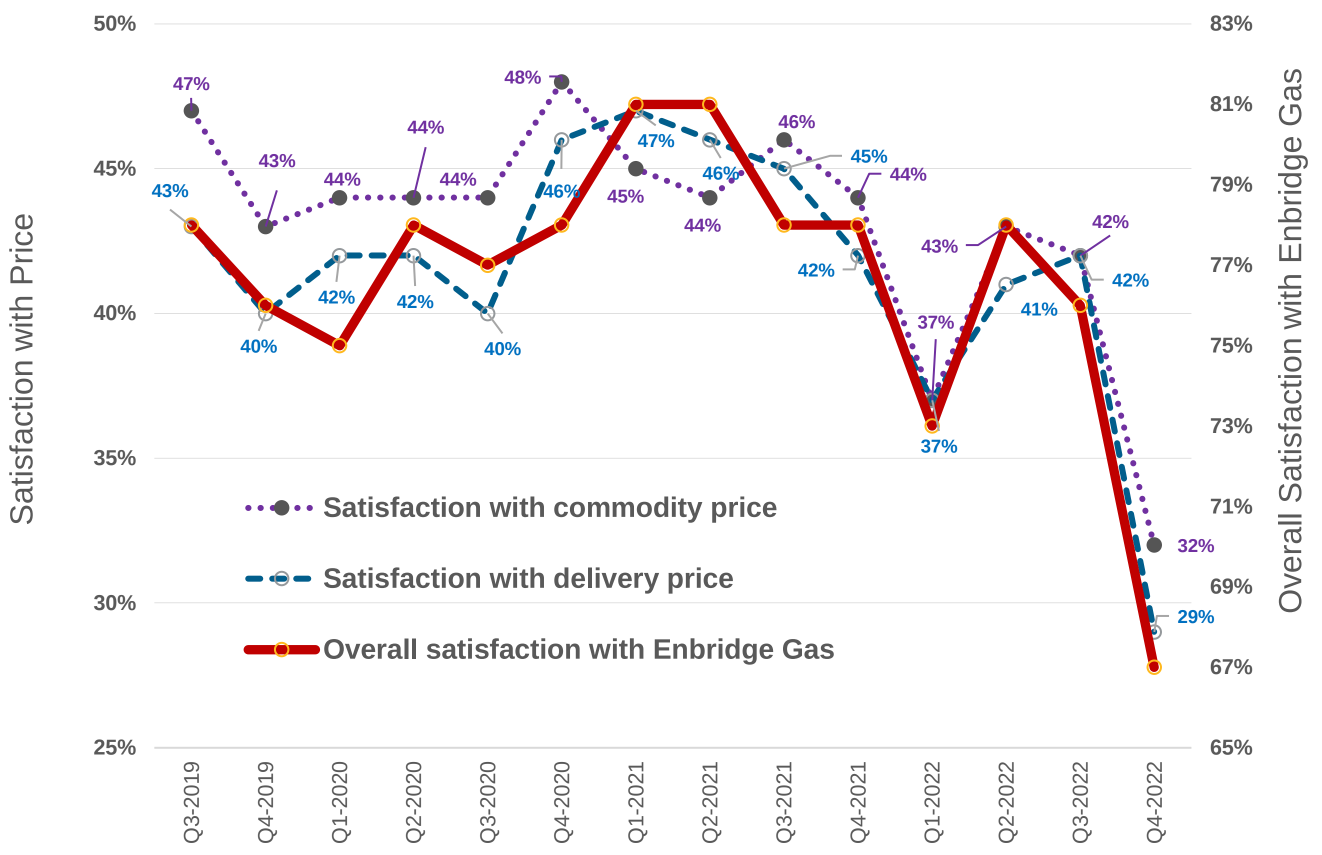
The correlation between natural gas prices and customer satisfaction has been strong for many years, (documented by both Legacy utilities prior to 2019), but became more pronounced in 2022, perhaps due to magnitude of the increases and broader inflationary and economic pressures being faced by many customers.

Strength of Associations:

Quantitatively, the relationships between customer satisfaction, prices, and overall impression are:

- Correlation between 'overall satisfaction with Enbridge Gas' and satisfaction with the commodity price = 0.86. ***(High)***
- Correlation between 'overall satisfaction with Enbridge Gas' and the delivery price = 0.94. ***(High)***
- Correlation between "overall satisfaction with Enbridge Gas" and "Overall impression of Enbridge Gas" (overall Enbridge brand perception) = 0.95. ***(High)***

Movements in Overall Satisfaction with Enbridge Gas Strongly Linked to Satisfaction with the Commodity and Delivery Prices



Enbridge Gas Residential Overall

Stated Sources of Dissatisfaction

ENBRIDGE

Primary Reasons for Dissatisfaction

"Why are you dissatisfied?" (Open-ended question, coded)

1. High natural gas bill
2. Natural gas price
3. Consumption estimate accuracy
4. Customer Service
5. Perception that Some third-party service providers are associated with Enbridge Gas (Reliance, Enercare, etc.).

Reason for Dissatisfaction	2019	2020	2021	2022
Base:	88	145	151	212
The price / Too expensive	34%	38%	36%	44%
Poor customer service / not helpful / not friendly	24%	18%	22%	25%
Extra fees / Delivery fee	13%	9%	8%	10%
Bill is confusing / Incorrect billing	6%	5%	16%	6%
Difficulty dealing with third party companies (e.g., Reliance, Enercare, etc.)	0%	0%	2%	4%
Lack of communication	10%	4%	7%	3%
Lack of competition / Monopoly	5%	3%	3%	2%
Neutral	18%	15%	16%	9%
Other	5%	11%	2%	8%
No answer / Don't know / Refused	2%	12%	8%	6%

85%

Reasons for Dissatisfaction – Sample Comments

"Because right now the price goes up too much"

"They keep raising the rates without letting me know"

"The price. It's doubled in just over a year"

"The bill is gone up, it's higher than it's ever been"

"I think squeezing us for too much money, the elder people should get a break and I have a problem paying this bill. The service is excellent, Enbridge is a good company, I am not happy and they need consider the pricing, the pricing is too high"

"Keep estimating how much gas I use. If I don't pay. Haven't been at my place for a year I can't reach anyone to talk to them"

"Last year I was overcharged by 400 because of estimating my gas consumption. I get a credit and then in the summer they deducted it. Now they're doing the same thing again even with the credit coming to me …. "

"I ask things and I don't get square answers"

"We got a letter from Lake Side and that Enbridge Gas put them in charge. Totally ticked off"

Enbridge Gas Residential Overall

Brand Attributes

ENBRIDGE

Overall Brand Perceptions

"Using a scale of 1 to 10, where 1 is "poor" and 10 is "excellent", how would you rate your overall impression of Enbridge Gas as a company?"

71%*

Top-3 Box Score (2022 Year-end)

Overall Impression of Enbridge Gas

- "Overall Impression of Enbridge Gas" is a summary for how customers feel about the brand. This could include perceptions of the utility and also the broader Enbridge Inc. brand.
- To understand in more detail how customers perceive aspects of the brand, a series of questions are asked about specific brand attributes. Enbridge Gas scores highest on reliability as well as other "table stakes" attributes fundamental to the business – being safe, easy to do business with, and trustworthy.

Ratings by Brand Attribute

"Using a scale of 1 to 10, where 1 means "poor" and 10 means "excellent", how would you rate Enbridge Gas on each of the following …?"

	Top 3 Box Scores							
Brand attribute:	**2019**	**2020**	**2021**	**2022 Q1**	**2022 Q2**	**2022 Q3**	**2022 Q4**	**2022**
Overall impression of Enbridge Gas	**73%**	**75%**	**76%**	**72%**	**74%**	**74%**	**64%**	**71% ***
Their reliability in providing your home with natural gas	92%	93%	93%	91%	93%	93%	91%	92%
Providing hassle free service	76%	76%	76%	73%	77%	76%	68%	74% *
Making the safety of its customers a top priority	74%	77%	77%	74%	77%	77%	72%	75%
Being easy to do business with	73%	74%	75%	72%	75%	73%	66%	72% *
Being a trustworthy company	71%	74%	75%	69%	75%	74%	66%	71% *
Being a credible energy expert	68%	67%	69%	63%	68%	71%	60%	65% *
Operating at the highest ethical standards	59%	61%	62%	56%	60%	62%	52%	57% *
Being customer focused	60%	61%	62%	54%	61%	62%	53%	57% *
Being accountable for its actions	56%	58%	57%	53%	57%	56%	49%	54% *
Being environmentally responsible	52%	52%	51%	49%	53%	52%	46%	50%
Offering a variety of energy conservation programs	44%	45%	44%	42%	43%	43%	35%	41%
Actively participating in the communities where it does business	35%	36%	35%	33%	36%	32%	26%	32% *
Continually looking for ways to provide better value	40%	43%	42%	35%	42%	37%	28%	36% *

** Significant movement over 2021 at the 95% confidence level.*

Enbridge Gas Residential Overall

Enbridge Gas Communications

ENBRIDGE

Overall Communications

Using a scale of 1 to 10 where 1 means "poor" and 10 means "excellent", how would you rate Enbridge Gas on communicating information to its' customers overall?"

54%*

Top-3 Box Score (2022 Year-end)

Overall Satisfaction with Enbridge Gas Communications

- "Overall Satisfaction with Enbridge Gas Communications" is a summary for how customers feel about the utility's communications overall. Customers could be thinking about a few different things when answering this question – the bill, social media posts, marketing campaigns, etc.
- To understand in more detail how customers perceive aspects of Enbridge Gas' communications, a series of questions are asked about specific communication attributes. As well, the perceived usefulness of a few different types of information is gauged.

Ratings by Communication Attribute

"Using a scale of 1 to 10, where 1 means "poor" and 10 means "excellent", how would you rate Enbridge Gas on each of the following …?"

	Top 3 Box Scores							
Communications attribute:	**2019**	**2020**	**2021**	**2022 Q1**	**2022 Q2**	**2022 Q3**	**2022 Q4**	**2022**
Overall satisfaction with Enbridge Gas communications	**57%**	**58%**	**57%**	**54%**	**54%**	**57%**	**50%**	**54% ***
Providing information that is relevant	53%	54%	57%	54%	55%	55%	47%	53% *
Using language that is clear and easy to understand	68%	71%	73%	69%	71%	74%	63%	69% *
Providing an appropriate amount of information	54%	56%	58%	55%	54%	55%	47%	53% *
Conveying information in a way that gets your attention	47%	49%	50%	48%	50%	47%	42%	47% *

Information Provided: Perceptions of Usefulness

"Using a scale of 1 to 10 where 1 is "poor" and 10 is "excellent", how would you rate the usefulness of the information you receive from Enbridge Gas through the following channels?"

	Top 3 Box Scores							
Perceptions of the usefulness of information received from Enbridge Gas:	**2019**	**2020**	**2021**	**2022 Q1**	**2022 Q2**	**2022 Q3**	**2022 Q4**	**2022**
Monthly gas bill	67%	65%	66%	63%	63%	67%	59%	63%
Website, social media, newspapers, magazines or community events	36%	35%	36%	32%	33%	32%	28%	31% *
Directly provided to you via email	50%	56%	58% *	54%	52%	55%	48%	52% *

** Significant movement over 2021 at the 95% confidence level.*

Enbridge Gas Residential Overall

Enbridge Bill & Bill Inserts

Ratings by Natural Gas Bill Attribute

"Thinking now about your monthly Enbridge Gas bill, please rate the following aspects of the bill on a scale of 1 to 10 where 1 means "poor" and 10 means "excellent"?"

	Top 3 Box Scores							
Bill attribute:	**2019**	**2020**	**2021**	**2022 Q1**	**2022 Q2**	**2022 Q3**	**2022 Q3**	**2022**
Clearly showing how your total price is calculated	76%	78%	76%	75%	76%	79%	67%	74%
Providing a bill that is easy to understand	77%	79%	78%	74%	77%	78%	71%	75% *
Providing an accurate bill	79%	80%	79%	74%	78%	80%	71%	76% *
Is easy to read and review electronically	79%	79%	80%	80%	78%	82%	71%	78%
Convenience to pay your monthly Enbridge gas bill	89%	90%	90%	90%	89%	90%	87%	89%

- Perceptions of the bill and the bill inserts (both paper and e-bill) are shown here.
- Bill inserts are used to communicate safety messages, rate changes and other important information about Enbridge Gas services. Additionally, programs and services such as Demand Side Management (DSM) offers are frequently promoted. The survey does not differentiate between these various types of bill inserts – respondents rate the bill inserts in general.

Bill Insert Readership by Bill Presentment Type

Customers Receiving a Paper Bill

"Thinking specifically about the brochures and other materials that are included with your monthly Enbridge Gas bill, would you say you read them thoroughly, skim them for useful information or discard them without looking at them?"

Bill Insert Readership Behavior	**2019**	**2020**	**2021**	**2022 Q1**	**2022 Q2**	**2022 Q3**	**2022 Q4**	**2022**
Read them thoroughly	31%	27%	32%	30%	25%	25%	37%	29%
I skim them for useful information	54%	59%	53%	55%	54%	61%	52%	55%
I discard them without looking at them	15%	12%	13%	14%	19%	13%	9%	14%

Customers Receiving a E-Bill

"Which of the following statements best describes what you usually do when you receive your monthly Enbridge Gas eBill?"

Bill Insert Readership Behaviour	**2019**	**2020**	**2021**	**2022 Q1**	**2022 Q2**	**2022 Q2**	**2022 Q4**	**2022**
I sign into my Enbridge Gas online account	34%	29%	31%	38%	26%	34%	38%	34%
I click on the links provided on the e-bill message and read them thoroughly	23%	22%	23%	26%	24%	18%	24%	23%
I click on the links provided on the e-bill message and skim for useful information	33%	33%	34%	39%	35%	34%	28%	34%
I don't click on the links provided on the e-bill message	37%	39%	38%	37%	35%	36%	35%	36%

* Significant movement over 2021 at the 95% confidence level.

Enbridge Gas Residential Overall

Website & Online Account Management Tool

Website
(enbridgegas.com & uniongas.com separate prior to mid-2021)

83%
2021: 85%
2020: 84%
2019: 82%

Customers who have access to and use the internet

12%
2021: 12%
2020: 10%
2019: 8%

Customers who report visiting the websites in the past 3 months

58%
Top-3 Box Score
(2022 Year-end)

Overall Satisfaction with Enbridge Gas Website

2019: 54%
2020: 60%
2021: 65%

Online Account Management Tool
(separate tools for each Legacy utility prior to mid-2021)

71%
Top-3 Box Score
(2022 Year-end)

Overall Satisfaction with online account management tool

2019: 69%
2020: 73%
2021: 74%

INTERNET ACCESS: *"Do you have access to and use the Internet (from any location)?"*

WEBSITE VISITS: *"Did you visit the website for any reason other than viewing your monthly Enbridge Gas bill in the past 3 months?"*

WEBSITE SATISFACTION: *"Taking into consideration all aspects of your visit website, how would you rate your satisfaction with your overall experience using a 1 to 10 scale where 1 means "completely dissatisfied" and 10 means "completely satisfied"?"*

ONLINE ACCOUNT SATISFACTION: *Our records indicate that you are currently registered to Enbridge Gas' online account management system sometimes called "MyAccount". How would you rate your overall satisfaction with your online account management system on a scale of 1 to 10, where 1 means you are "completely dissatisfied´´ and 10 means you are "completely satisfied"?"*

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Section 2:

Enbridge Gas Contact Centre Experience

- Overall satisfaction with the call centre experience
- Level of effort & issue resolution
- Customer Service Representative (CSR) soft skills
- Experience with self-service tools prior to speaking to a live representative
- Preferences for future contact with Enbridge Gas

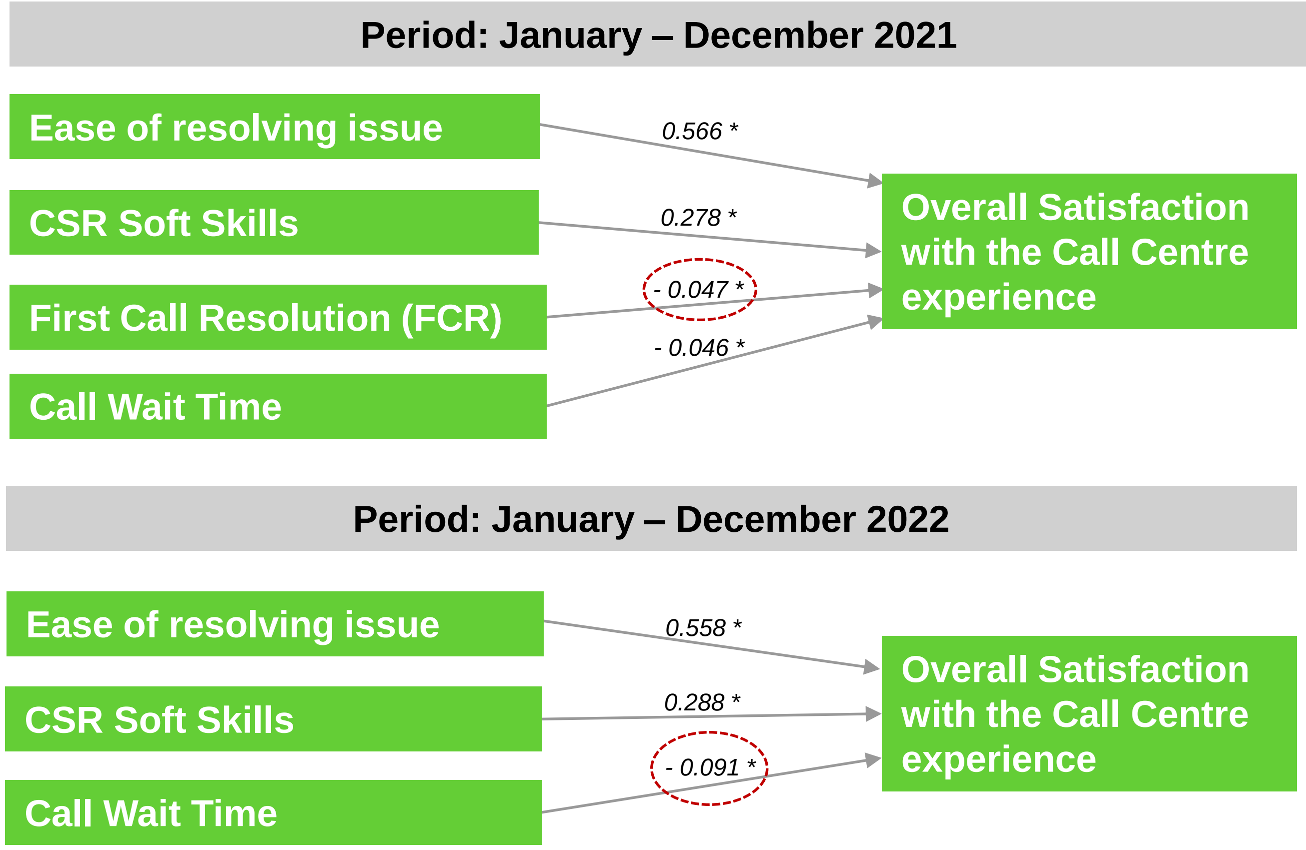
Call Centre Experience

2022 Year-end Spotlight

ENBRIDGE

- 'Overall satisfaction with the Call Centre experience' dropped significantly in 2022 compared to 2021.
- The "overall ease of resolving the issue" experienced a similar statistically significant loss, comparing the 2022 result to 2021.
- A change is noticed in the key drivers of overall satisfaction with the Call Centre experience, with the "ease of resolving the issue" becoming a stronger driver of overall satisfaction in 2022. The "ease of resolving the issue" and CSR soft skills are now the dominant key drivers of overall satisfaction with the Call Centre experience, explaining 90% of variations in customer satisfaction.
- As previously observed, high ratings for overall customer satisfaction can be achieved if perceptions of the CSR's soft skills are positive – even when the issue the customer called about is not resolved, or not resolved quickly. This is particularly true if the CSR is perceived to genuinely want to help the customer.
- Another (but much weaker) key driver is the "call wait time", having a negative relationship with overall satisfaction.

Key Drivers of Overall Satisfaction with the Call Centre Experience (Live Calls)



** Standardized beta coefficient using linear regression model.*

Call Centre Experience

Overall Satisfaction with the Call Centre Experience

Overall Satisfaction with the Call Centre

"Overall, how satisfied were you with your most recent call centre experience? Please use a scale of 1 to 10 where 1 is "completely dissatisfied" and 10 is "completely satisfied"?"

64%*

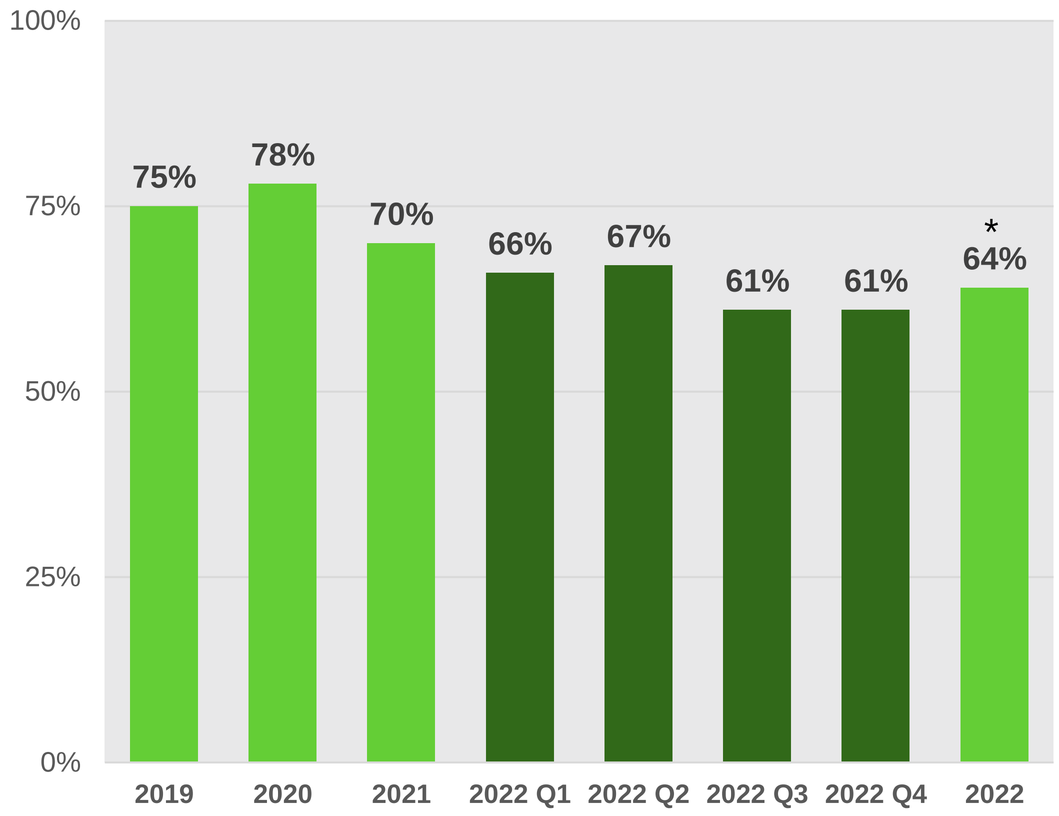
Top-3 Box Score (2022 Year-end)

Overall Satisfaction with the Call Centre Experience

2019: 75%
2020: 78%
2021: 70%

- "Overall Satisfaction with the Call Centre experience" is a summary for how customers feel about their experience with the Brantford, Thunder Bay or Accenture call centers (general "contact us" lines).
- Only customers who recently connected and spoke with a live agent are eligible for this particular survey – customers who successfully self-served through the IVR or another tool are not included.

Overall Satisfaction with the Call Centre experience (Historical Trend)



* Statistically significant movement compared to 2021 at the 95% confidence level.

Call Centre Experience

Issue Resolution

ENBRIDGE

Ease of Resolving the Issue (Level of Effort)

"Overall , how easy was it for you to resolve your question/concern/issue with Enbridge during your most recent call centre experience? Please use a scale of 1 to 10 where 1 is "very difficult" and 10 is "very easy"?"

59%*
Top-3 Box Score
(2022 Year-end)

Overall Ease of Resolving the Issue

2019: 70%
2020: 74%
2021: 66%

- This "level of effort" survey question gauges how easy it is for customers to do business with Enbridge Gas. Research suggests level of effort can be a better predictor of customer loyalty and repeat business than more traditional customer satisfaction metrics.
- Linked to level of effort is the number of calls required to resolve the issue/concern/question. The issue resolution results shown here are from the individual customer's perspective. It is possible the agent felt the issue was resolved, but the customer did not.

Issue Resolution

"Was your question / concern / issue resolved during your first call?"
"Was your question / concern / issue resolved in subsequent phone calls?"

First Call Resolution

Was the issue/concern/question resolved on the first call?

2022

65%* **Yes**
2019 Baseline: 78%
2020: 78%
2021: 70%

32%* **No**
2019 Baseline: 20%
2020: 20%
2021: 27%

Note: Totals of '% yes' and '% no' do not equal 100% due to respondents answering "don't know" to these questions.

Total Call Resolution

Was the issue/concern/question resolved on a subsequent call?

2022

32% **Yes**
2019 Baseline: 40%
2020: 37%
2021: 33%

59% **No**
2019 Baseline: 50%
2020: 57%
2021: 56%

* Statistically significant movement compared to 2021 at the 95% confidence level.

Call Centre Experience

Impressions of the Customer Service Rep. (CSR)

ENBRIDGE

Perceptions of CSR's Commitment to Help

"Now, I'm interested in your impression of the Customer Service Representative's or CSR's commitment to help you with your issue. Please use a scale of 1 to 10 where 1 means that the CSR was "Not At All Genuine" in their commitment to help you and 10 means "Very Genuine" in their commitment to help you."

76%*

Top-3 Box Score

(2022 YTD)

CSR's Genuine Commitment to Help

2019 Baseline: 84%
2020: 85%
2021: 81%

Satisfaction with CSR by "Soft Skill" Attribute

"How satisfied were you with the representative you spoke with on the following aspects of service? Please use a scale of 1 to 10 where 1 is "completely dissatisfied" and 10 is "completely satisfied"."

Service attribute:	*Top 3 Box Scores*							
	2019	**2020**	**2021**	**2022 Q1**	**2022 Q2**	**2022 Q3**	**2022 Q4**	**2022**
Answering your phone call promptly, without a lengthy waiting period	73%	73%	60%	58%	60%	59%	61%	59%
The courtesy of the representative	88%	90%	86%	86%	85%	82%	79%	83% *
Being able to answer your questions	81%	83%	78%	74%	75%	71%	67%	72% *
Timeliness of resolving your problem, question, or request	76%	78%	70%	68%	69%	62%	60%	65% *
Ability to explain things in a way that is easily to understand	82%	84%	79%	76%	77%	72%	69%	73% *

- Customers are asked to rate the Customer Service Representative (CSR) they spoke to on several "soft skill" attributes. These attributes are based on characteristics/behaviours emphasized in CSR training.
- Soft skills are linked to overall customer satisfaction with the call centre experience and can "redeem" customer satisfaction in instances where first call resolution does not occur and/or the level of effort to resolve the issue is considered high.
- The CSR's ability to answer the customer's questions is the most important soft skill in terms of driving overall satisfaction with the call centre experience. This soft skill is also not surprisingly a strong penalty attribute (also known as a "table stakes" attribute), meaning customers will penalize for its absence with lower overall satisfaction, but typically not respond with higher satisfaction when delivered.

* Significant movement compared to 2021 at the 95% confidence level.

Call Centre Experience

Experience with the IVR (prior to call with CSR)

Satisfaction with Ease of Understanding IVR (rated by customers who spoke to a CSR)

"Thinking of the IVR automated "press or say" system, how would you rate the system on the ease of understanding the phone menu instructions, using a 1 to 10 scale where 1 is "completely dissatisfied" and 10 is "completely satisfied"?"

51%*

Top-3 Box Score (2022 Year-end)

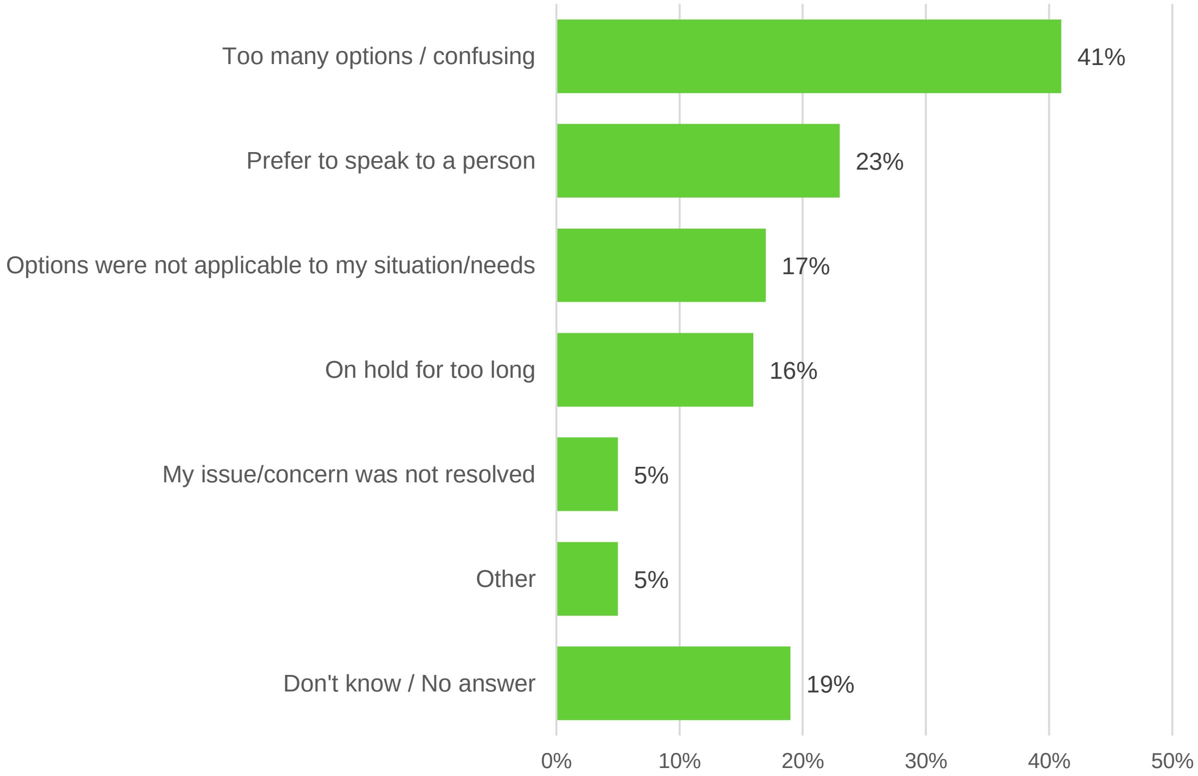
Ease of Understanding the IVR Menu

2019 Baseline: 59%
2020: 60%
2021: 56%

- These results are based on respondents who spoke to a CSR and do not reflect the many customers who successfully self-serve in the IVR without reaching a live agent.
- Given this, it is not surprising that many of the customers who find the IVR "less easy to use" simply prefer to speak to a person.

Reasons IVR Was Not Easy to Use (2022)

"What about the IVR wasn't easy to use?"



*Significant movement compared to 2020 at the 95% confidence level.

Call Centre Experience

Online Account Management Tools

Online Account Management Tools
(separate tools for each legacy utility prior to summer 2021)

Callers registered to use an online account management tool

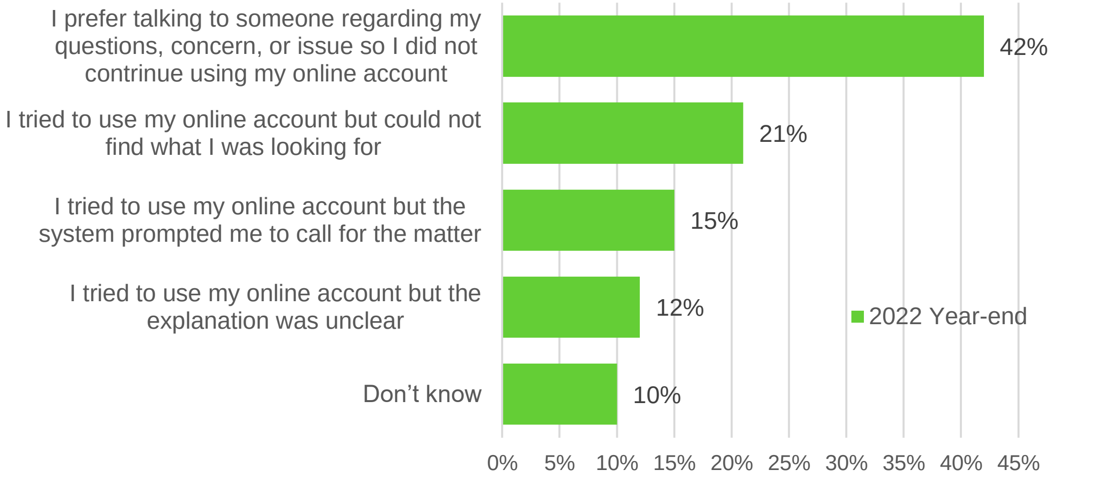
(as indicated in billing system)

Prior to your most recent contact, did you use Enbridge Gas' online account for your question, concern or issue?

38%
yes

2019 baseline: 23%
2020: 30%
2021: 36%

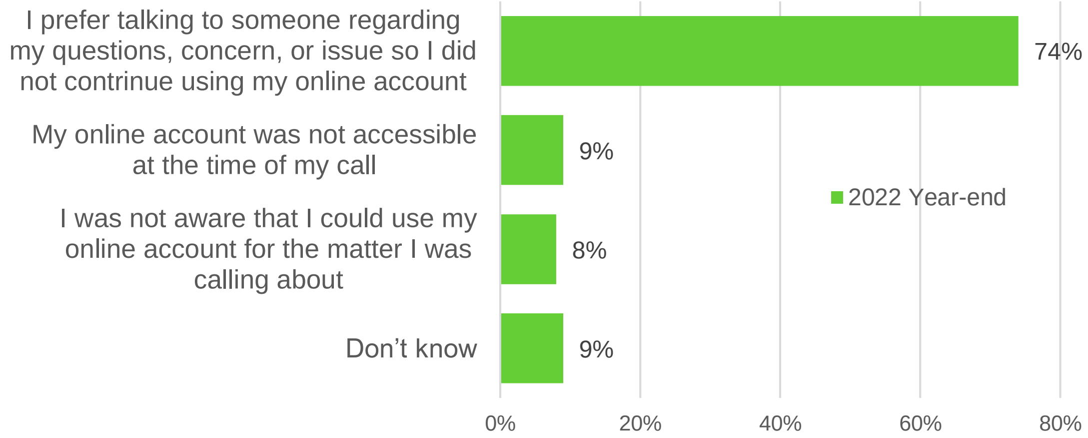
Which statement best describes your interaction with your online account?



57%
no

2019 baseline: 73%
2020: 66%
2021: 60%

Which statement best describes why you did not use your online account?



Don't know = 5%

Section 3:

Enbridge Gas Field Work Experience

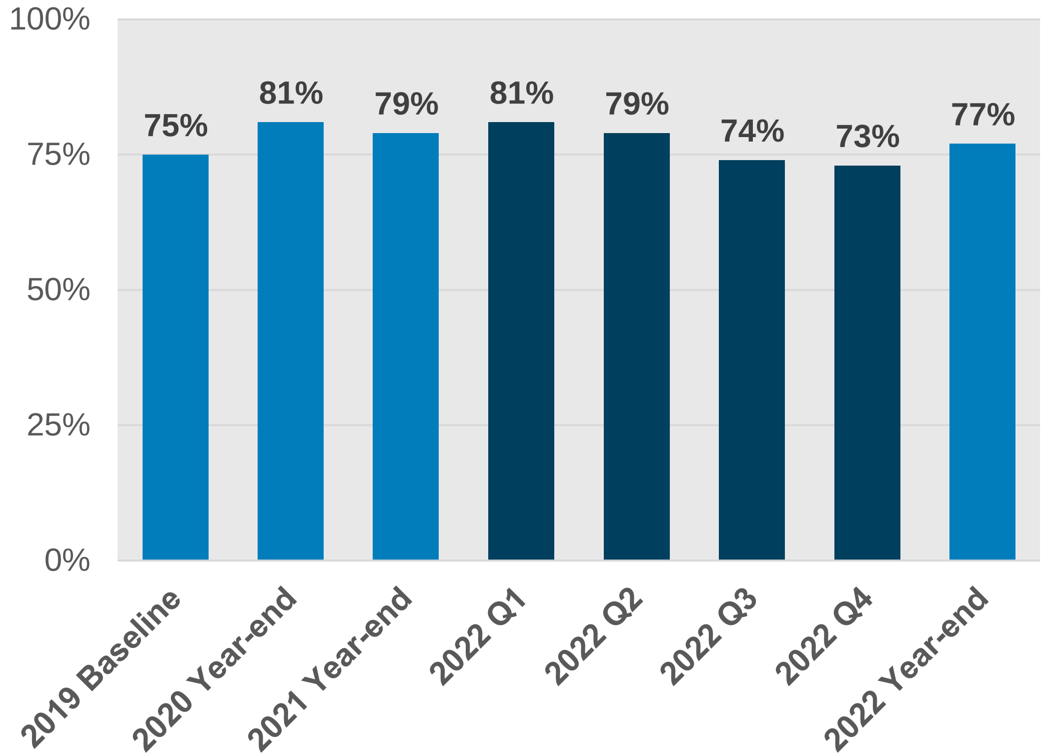
- Overall satisfaction with the field work experience
- Satisfaction with the Customer Service Representative (CSR)
- Satisfaction with the Service Technician

Field Work

2022 Year-end Spotlight

- Overall satisfaction with the field work experience is strong and has been above the 75% top-3 box goal for the past three years.
- 2022 year-end overall satisfaction with the field work experience is stable compared to previous years. Looking at the quarterly results, results were stronger in the first half of the year, which is consistent with previous patterns.
- For 2022, the most important drivers of overall satisfaction with the field work experience were identified as:
  - Technician's ability to answer questions
  - Perceptions of the technician as courteous
  - Appearance of the technician
- As in the past, satisfaction with the overall experience is more driven by the technician and the home appointment than by the appointment booking process.

Overall Satisfaction with the Field Work Experience



Field Work

Overall Satisfaction with the Field Work Experience

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Overall Satisfaction with the Field Work Experience

"Overall, how satisfied were you with your recent Enbridge Gas service experience? This includes the process of setting up an appointment as well as the service technician's visit to your home. Please use a scale from 1 to 10 where 1 means "completely dissatisfied" and 10 means "completely satisfied"

77%
Top-3 Box Score
(2022 Year-end)

Overall Satisfaction with the Field Work Experience

2019 Baseline: 75%
2020: 81%
2021: 79%

- "Overall Satisfaction with the Field Work Experience" is a summary for how customers feel about field work overall. In answering this question, customers are asked to think of all parts of the experience, including setting up an appointment and the technicians visit to the home.
- Overall results are stable compared to previous years.
- Results vary by region, as shown on the right side. Results are stable relative to 2021, with the exception of GTA East.

Overall Satisfaction with the Field Work Experience by Region

Region	*Top 3 Box Scores*			
	2019	**2020**	**2021**	***2022***
Toronto	66%	73%	74%	72%
GTA East	71%	78%	80%	72% *
GTA West & Niagara	73%	78%	78%	80%
Northern	80%	88%	84%	87%
Southeast	83%	87%	78%	79%
Southwest	84%	82%	78%	75%
Eastern	66%	79%	82%	78%

** Significant movement compared to 2021 at the 95% confidence level.*

Field Work

Satisfaction with the Customer Service Rep. (CSR)

ENBRIDGE

Overall Satisfaction with the CSR

"How would you rate your satisfaction with the customer service representative(s) you dealt with recently using a scale of 1 to 10 where 1 is "completely dissatisfied" and 10 is "completely satisfied"?

81%
Top-3 Box Score
(2022 Year-end)

Overall Satisfaction with the CSR

2019 Baseline: 78%
2020: 87%
2021: 83%

Region	*Top 3 Box Scores* 2019	2020	2021	2022
Toronto	78%	80%	78%	79%
GTA East	72%	83%	86%	76% *
GTA West & Niagara	74%	88%	82%	85%
Northern	85%	91%	88%	84%
Eastern	72%	85%	87%	86%
Southeast	80%	92%	81%	83%
Southwest	88%	89%	81%	76%

Ratings by CSR Attribute

"Please rate your satisfaction with the service technician who came to your home on the following aspects of service on a scale of 1 to 10 where 1 is "completely dissatisfied" and 10 is "completely satisfied"."

Service attribute:	*Top 3 Box Scores* 2019	2020	2021	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022
Overall satisfaction with the CSR	**78%**	**87%**	**83%**	**84%**	**82%**	**77%**	**80%**	**81%**
Answering phone promptly, without a lengthy waiting period	71%	76%	73%	72%	72%	71%	70%	72%
The courtesy of the representative	86%	92%	89%	89%	90%	85%	86%	87%
Being able to answer your questions	79%	85%	81%	82%	80%	74%	76%	78% *
Representative's concern for your needs	78%	86%	82%	84%	80%	76%	77%	79% *
Timeliness of resolving your problem, question, request	78%	84%	80%	82%	76%	73%	75%	77% *
The service being scheduled at time convenient to you	72%	82%	78%	80%	76%	75%	69%	75%
A clear arrangement when a technician would come to your home	76%	81%	77%	77%	75%	71%	70%	73%
Being able to arrange your emergency service without transferring or placing you on hold	84%	88%	87%	87%	80%	89%	87%	86%
Recognizing the urgency of your request	88%	93%	90%	92%	90%	91%	91%	91%
Providing explanation of what you should and should not do	87%	88%	83%	84%	78%	83%	83%	82%

** Significant movement over 2021 at the 95% confidence level.*

Field Work

Satisfaction with the Service Technician

ENBRIDGE

Overall Satisfaction with the Service Technician

"How would you rate your satisfaction with the service technician who visited your home? Please use a scale of 1 to 10 where 1 is "completely dissatisfied" and 10 is "completely satisfied"."

85%*

Top-3 Box Score (2022 Year-end)

Overall Satisfaction with the Service Technician

2019 Baseline: 86%
2020: 88%
2021: 87%

Region	*Top 3 Box Scores* 2019	2020	2021	2022
Toronto	75%	78%	81%	80%
GTA East	77%	87%	88%	77% *
GTA West & Niagara	79%	85%	86%	86%
Northern	85%	94%	92%	95%
Eastern	81%	88%	87%	88%
Southeast	88%	93%	89%	89%
Southwest	87%	91%	91%	86%

* *Significant movement over 2021 at the 95% confidence level.*

Ratings by Service Technician Attribute

"Please rate your satisfaction with the service technician who came to your home on the following aspects of service on a scale of 1 to 10 where 1 is "completely dissatisfied" and 10 is "completely satisfied"."

Service attribute:	*Top 3 Box Scores* 2019	2020	2021	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022
Overall Satisfaction with the service technician	**86%**	**88%**	**87%**	**85%**	**87%**	**85%**	**84%**	**85% ***
Arrived within the promised service window	78%	85%	82%	84%	84%	69%	73%	77% *
Arriving within a reasonable amount of time *(emergency service)*	84%	90%	87%	87%	90%	91%	88%	89%
Appearance of the technician	86%	89%	88%	88%	87%	88%	86%	87%
Being courteous	90%	91%	91%	90%	90%	89%	87%	89% *
Their attention to safety	86%	88%	88%	87%	85%	86%	83%	85% *
Clearly explaining the work to you	82%	84%	84%	83%	84%	82%	77%	81% *
Being able to answer your questions	83%	85%	85%	83%	82%	80%	80%	81% *
Completing the work correctly first time	84%	86%	85%	84%	84%	81%	82%	83%
Providing you with information on who to contact in case you had any problems or questions	68%	70%	71%	68%	66%	66%	64%	66% *
Having your NG service restored promptly	87%	91%	90%	94%	89%	87%	90%	90%
Recognizing the urgency of your request	87%	91%	88%	89%	92%	93%	87%	90%
How quickly the technician identified the problem	87%	86%	86%	85%	89%	88%	84%	86%
Ensuring you that your home was made safe before leaving	93%	90%	89%	87%	90%	88%	87%	88%

CUSTOMER EXPERIENCE

Voice of the Customer (VoC) Operations Report

December 31st, 2022

accenture ENBRIDGE Life Takes Energy™

VOC OPERATIONS REPORT

December 31st, 2022

	Call Centre Inquiry	First Bill	Moves Process	Ebill/ Paper Bill Received	MXGI	LBA Inquiry	Emergency	Relationship (General)[1]	Chatbot
TOTAL RESPONSES YEAR END	70,701	4,602	11,602	9,940	4,239	534	3,782	10,868	2,043
RESPONSE RATE	17%	5%	10%	6%	24%	16%	21%	5%	20%
SATISFACTION YEAR END	69%	57%	87%	61%	87%	97%	89%	63%	39%
Q1, 2022	72%	50%	86%	64%	93%	97%	89%	64%	37%
Q2, 2022	74%	62%	87%	68%	87%	97%	91%	65%	42%
Q3, 2022	68%	61%	86%	59%	81%	96%	87%	64%	36%
Q4, 2022	69%	58%	86%	52%	84%	97%	88%	58%	42%
SINCE LAST QUARTER	**+1%** ⇧	**-3%**	-	**-7%** ⬇	**+3%**	**+1%**	**+1%**	**-6%** ⬇	**+6%**

[1]The Relationship survey question was updated on December 1, 2020. Instead of asking a Net Promoter Score question about the likelihood to recommend Enbridge Gas, the survey now asks customers to rate their overall satisfaction with Enbridge Gas. The report shows Top 3 Box scores (scores of 8, 9, or 10 out of 10).

⇧ Denotes a statistically significant increase compared to the previous quarter.
⬇ Denotes a statistically significant decrease compared to the previous quarter.

ENBRIDGE Life Takes Energy

VOC OPERATIONS REPORT

December 31st, 2022

	Call Centre Inquiry	First Bill	Moves Process	Ebill/ Paper Bill Received	MXGI	LBA Inquiry	Emergency	Relationship (General)	Chatbot
SURVEY / INTERACTION TYPE DESCRIPTION	Residential customers who contacted the call centre and connected to a live agent the previous day	New residential customers who received their first bill	Residential customers who requested a move online the previous day	Randomly selected residential customers	Residential customers who had their meter replaced	Business customers who contacted the Large Business Accounts team	Residential customers who placed an emergency call and had a field technician visit	Randomly selected residential customers	Customers who connected with Chatbot cozE™ and connected to a live agent the previous day

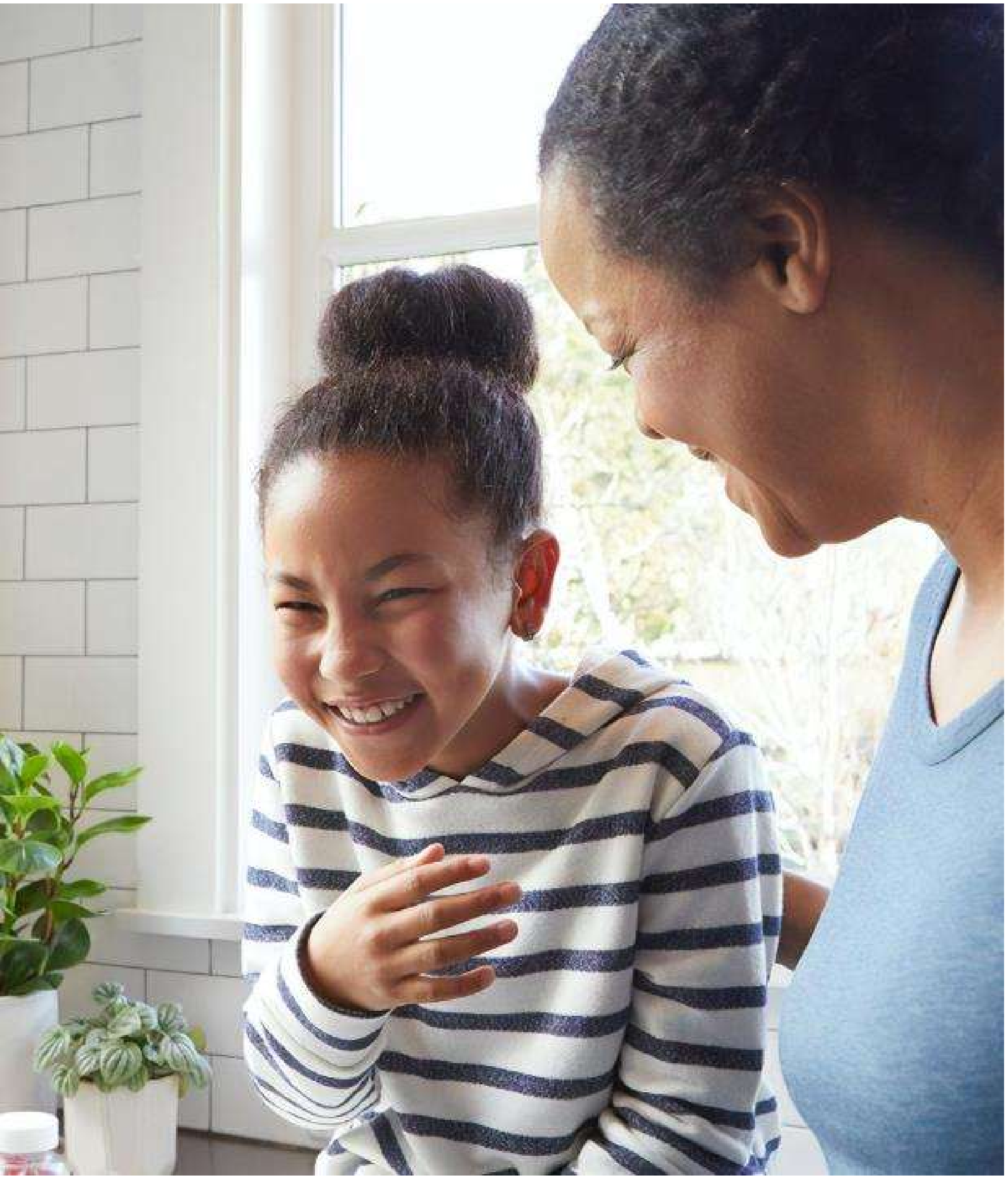
ENBRIDGE brand health 2022

quantitative research report

November 15, 2022

RESEARCH STRATEGY GROUP

ENBRIDGE®



contents

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background and objectives

- In October 2020, **RESEARCH STRATEGY GROUP** conducted a quantitative research study on behalf of Enbridge Gas Inc (EGI) that included some questions focused on brand health, such as brand awareness, attitudes & perceptions, familiarity, associations, etc.
- A full brand health research study was designed in 2021 with the following objectives:
  - Track if progress has been made on brand awareness and perceptions of Enbridge and Enbridge Gas
  - Measure perceptions of natural gas and energy transition
  - 50% of the survey was new content in 2021, while tracking was available on approx. 50% of the survey
- Another wave of brand health research has now been conducted in 2022, with tracking available for 90% of the questions vs. 2021
- More specifically, the goals of this brand health research are to:
  - Measure awareness of and associations with Enbridge and Enbridge Gas
  - Measure brand perceptions (familiarity, opinions, trust, associations) of and with Enbridge Gas
  - Understand the role of natural gas as a fuel/energy source today and in the future, and measure future usage expectations
  - Measure current concern over how energy is generated, where energy is sourced, and climate change
  - Measure perceptions of the role of Enbridge Gas in energy transition and ensuring a sustainable energy future

method

1613 online interviews were conducted in English using sample from our panel partners, Asking Canadians

- Survey length: 15-minutes

Respondent qualifications

- Ontario residents
- Aged 18+
- Not employed in sensitive industries
- Representative sample by age and gender
    - n=155 interviews among 18 – 25 year olds were conducted to ensure sufficient sample for analysis of findings among this key subgroup

Fieldwork dates

- 2022: October 21 – 31, 2022
- 2021: December 3 – 13, 2021
- 2020: October 19 – 27, 2020

method – interpretation notes

- **Interpretation of data differences:**
  - # = significantly higher versus all other subgroups at 95% confidence level
  - # = significantly lower versus all other subgroups at 95% confidence level
  - ⬆ = significantly higher versus the previous year at 95% confidence level
  - ⬇ = significantly lower versus the previous year at 95% confidence level

- **Understanding NETs**
  - When questions are asked in an open-ended format (i.e. respondents are not provided with a list of answers to select from, rather they write in their responses in their own words), the verbatim answers are then coded to turn qualitative responses into quantitative information
  - NETS are used to organize and summarize codes into similar themes, with the NET indicating the proportion of respondents who selected one or more of the codes that fall within this theme (NET)

- **Interpretation of pre-defined subgroups**
  - Respondents have been categorized into EGI customers and EGI non-customers
    - EGI customers were defined based on answers at Q6 (What is the name of the company that delivers natural gas to your home?) and identifying which are in fact current customers

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summary of findings

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summary of findings: awareness & perceptions

- Overall, the majority of key metrics are **stable this year**.

- Two-in-five respondents recall Enbridge on an unaided basis (stable since 2020).
  - When asked what **Enbridge** does, two-thirds think of Enbridge as a supplier of natural gas.
    - **Enbridge** is more likely to be associated with an Ontario-based utility that delivers natural gas than a leading North American energy infrastructure company; though one-third think of **Enbridge** as both.
  - When asked about **Enbridge Gas**, over half think of it as a supplier of natural gas.
    - **Enbridge Gas** is also more likely to be associated with an Ontario-based utility that delivers natural gas than a leading North American energy infrastructure company; though one-third think of **Enbridge Gas** as both.

- 79% of respondents are aware of **Enbridge** and 74% are aware of **Enbridge Gas**, on an aided basis.
  - When netted together, awareness of Enbridge Gas and/or Enbridge is 88% (stable since 2020).

- 70% of respondents report using natural gas, with 64% reporting that Enbridge/Enbridge Gas is the company that delivers natural gas to their home.
  - Mentions of Union Gas are on par with last year at 4% - of this group who report that Union Gas is their provider, 57% are aware that Union Gas merged with Enbridge Gas Distribution to become Enbridge Gas (down from 67% last year).
  - Younger respondents (18-25 years old) are less likely to know who their natural gas provider is, confirming the importance of building awareness among this group.

summary of findings: awareness & perceptions

- There continues to be very little differentiation between **Enbridge** and **Enbridge Gas**.
  - Familiarity, experience and perceptions of the two entities continue to be essentially on par and stable over time.
    - About 1-in-5 respondents are very familiar with and have a lot of experience with **Enbridge** and **Enbridge Gas**.
    - Nearly half of respondents aware of **Enbridge** and **Enbridge Gas** have very or somewhat favourable opinions, however a decline in the proportion of respondents who have a 'very favourable' opinion is noted this year for both **Enbridge** and **Enbridge Gas**.
      - Unfavourable opinions for **Enbridge Gas** continue to centre around the perceived high cost of natural gas, with an increase in mentions of rate increases this year – high costs appear to be overshadowing environmental concerns.
    - 85% find both **Enbridge** and **Enbridge Gas** to be very or somewhat trustworthy, however similar to favourability, the proportion of respondents who feel **Enbridge** and **Enbridge Gas** are 'very trustworthy' has declined this year.
    - Three-quarters of respondents aware of **Enbridge Gas** perceive the company to be very or somewhat innovative and sustainable *(new metrics added in 2022)*.

- When evaluating **Enbridge Gas** against a revised list of 8 brand attributes, it is most strongly associated with "Reliable" and "Essential", both selected by 51% of respondents. Associations with both of these attributes are nearly twice as high among customers vs. non-customers.
  - One-quarter of EGI non-customers do not associate **Enbridge Gas** with any of the attributes.
- When evaluating **Enbridge Gas** against 10 business attributes, it is most strongly associated with being "a natural gas storage and distribution company" (58%) and "a leader in the provision and distribution of energy" (31%).

- Key metrics for both **Enbridge** and **Enbridge Gas** continue to be significantly higher among EGI customers (who skew older).

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2022

comparison & trend of key metrics

unaided awareness of
Enbridge/Enbridge Gas (NET)
40%

aided awareness of
Enbridge/Enbridge Gas (NET)
88%

	familiarity Top 3 box (% 8-10)	experience Top 3 box (% 8-10)	favourability % very/somewhat	trustworthiness % very/somewhat	innovative* % very/somewhat	sustainable* % very/somewhat
Enbridge	19	20	46	85	n/a	n/a
Enbridge Gas	24	23	48	85	74	73

= significantly higher/lower versus the previous year at 95% confidence level

* Metric added in 2022

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summary of findings: natural gas & energy transition

- Natural gas continues to be seen as having many roles as a fuel source. Most commonly, natural gas is seen as a practical alternative to oil and electricity, as well as easily accessible and the best energy option for the home.
- Natural gas will continue to have a role as an energy source in the future. It is anticipated to be a back up to wind and solar and an alternative to other fossil fuels.
- 71% of respondents expect their use of natural gas to remain the same over the next 5 years, while 15% expect an increase due to plans to purchase new appliances, more people joining their household, or moving to a larger residence.

- Three-quarters of respondents are concerned about how the energy they use is generated, and three-quarters are concerned with where the energy they use comes from. Even more (84%) indicate concerns about climate change, and a similar 83% indicate an urgent need for action on climate change.
  - Energy generation/sources and climate change concerns/urgency of action continue to be driven by women.

- Roughly one-quarter of respondents are aware of **Enbridge Gas** offering energy conservation programs for homes/businesses – awareness of other initiatives that **Enbridge Gas** is doing to help ensure a sustainable energy future is low.
- Encouragingly, two-thirds of respondents are interested in and would like to learn more about at least one program that **Enbridge Gas** is doing to help ensure a sustainable energy future.
  - Highest interest is in energy conservation programs for homes and businesses to help them use less energy and reduce carbon emissions (36%), Enbridge Gas' commitment to achieving net zero emissions in its own operations by 2050 (29%), and Enbridge Sustain, a new line of business providing homeowners, businesses and builders with turnkey solutions with no upfront costs for low carbon technologies like geothermal, solar, and hybrid heating – *new in 2022* (28%).

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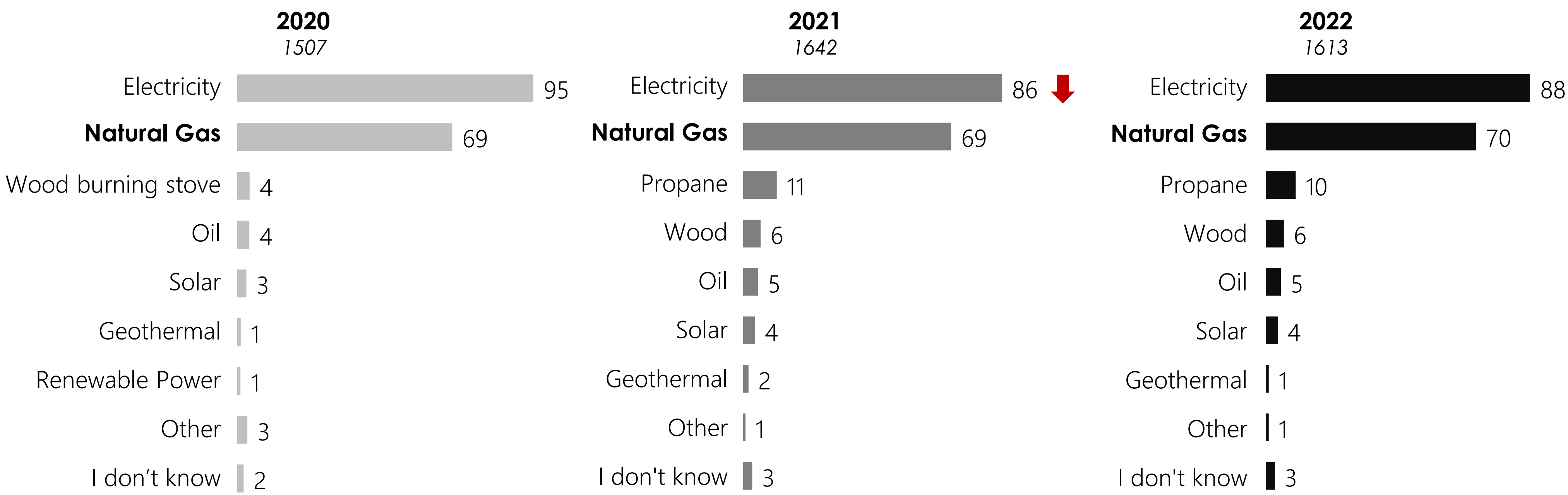
detailed findings

category use & knowledge

trend

mentions of natural gas as a source of energy for the home is steady at 70%

types of energy used in home (%)*



2020: S6.; Since 2021: Q3. Thinking about your primary residence now, from the list below, please select all the types of energy used in your home for lighting, heating, and cooking. Please select all that apply

**Note: the list of options was changed in 2021*

= significantly higher/lower versus the previous year at 95% confidence level

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2022

one-half of respondents report that natural gas is the primary energy source for heating their home

- A decline in propane usage is noted this year.

primary energy source for heating home (%)

	total *1613*	EGI customer *893*	EGI non-customer *720*
Natural Gas	55	83	19
Electricity	34	14	59
Propane	2	-	4 (-3)
Oil	2	-	3
Geothermal	1	-	2
Wood	1	-	1
Solar	0	-	1
Don't know	6	1	11

= significantly higher/lower versus the previous year at 95% confidence level

Q4. From the following list, which do you consider to be the primary energy source you use to heat your home? Please select one answer.

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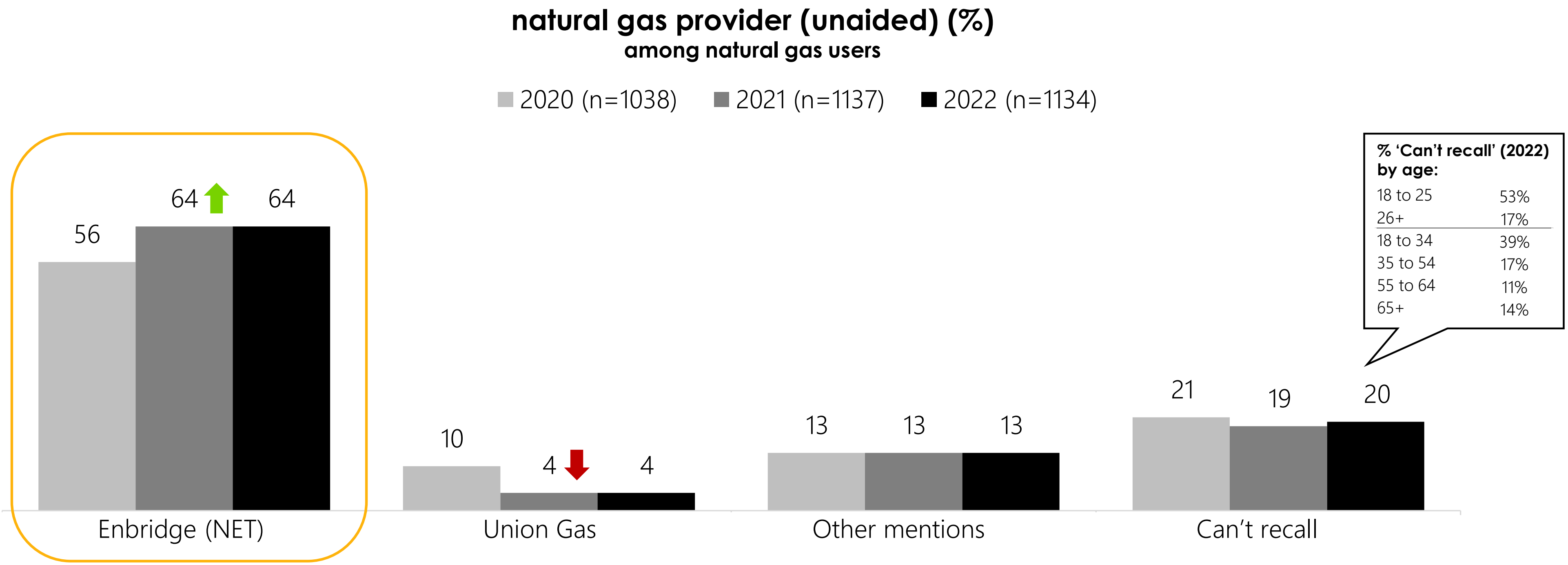
trend

mentions of Enbridge/Enbridge Gas as a natural gas provider are on par with last year

- Mentions of Union Gas are also on par with last year at 4% - of this group who report Union Gas as their provider, 57% are aware that Union Gas merged with Enbridge Gas Distribution to become Enbridge Gas (down from 67% last year).
- Younger respondents are less likely to know who their natural gas provider is.



= significantly higher/lower versus the previous year at 95% confidence level

2020: Q3.; Since 2021: Q6. What is the name of the company that delivers natural gas to your home?

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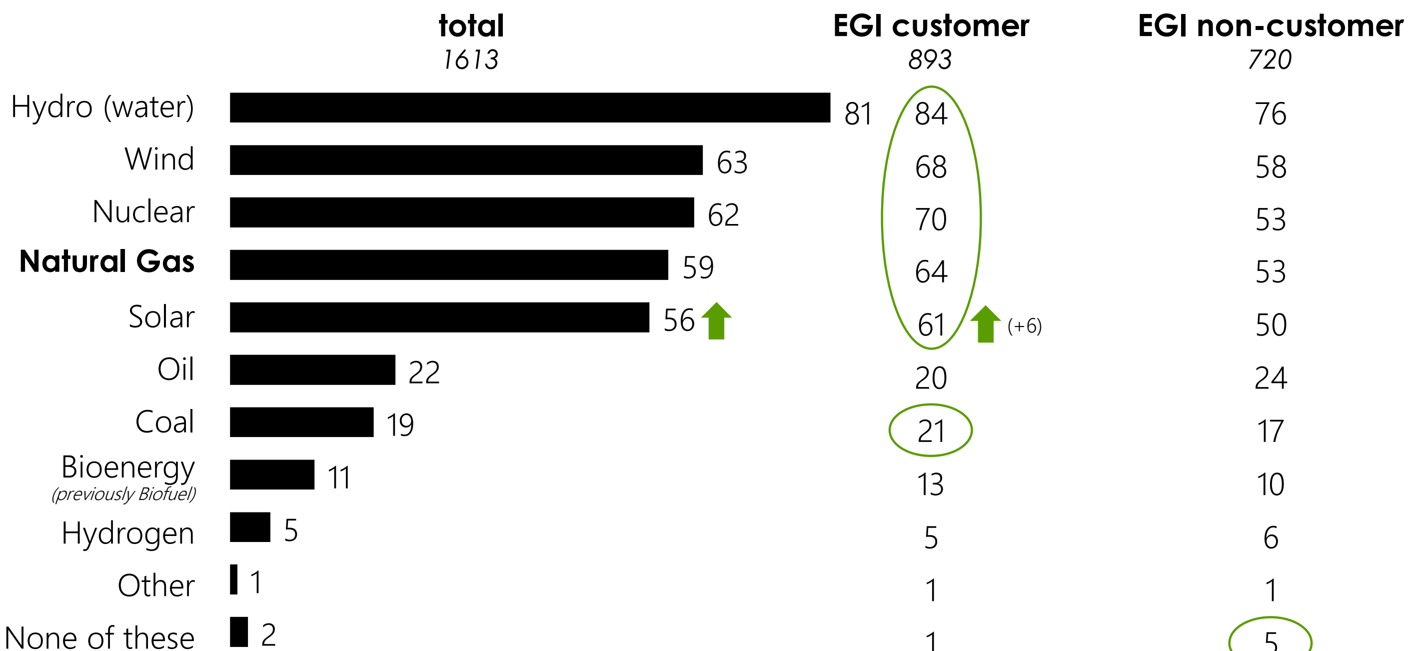
2022

more than half of respondents think natural gas is a source used to generate electricity in Ontario

- A higher proportion of EGI customers vs. non-customers think natural gas is a source currently used to generate electricity in Ontario.
- A significant increase in solar as a source of electricity in Ontario is noted this year, driven by EGI customers.

knowledge about energy sources in Ontario (%)



= significantly higher/lower versus the previous year at 95% confidence level

Q5. To the best of your knowledge what are the sources currently used to generate electricity in Ontario? Please select all that apply.

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brand awareness
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17

trend

Enbridge continues to achieve the highest unaided awareness of all energy companies

- Enbridge continues to be more top of mind among EGI customers vs. EGI non-customers.
- While unaided awareness for Enbridge has softened this year among EGI customers, results are higher compared to 2020.

unaided awareness – energy and energy infrastructure companies (%)

	Total			EGI customer			EGI non-customer		
	2020	**2021**	**2022**	**2020**	**2021**	**2022**	**2020**	**2021**	**2022**
Base:	*1507*	*1642*	*1613*	*785*	*864*	*893*	*722*	*778*	*720*
Enbridge (NET)	37	40	40	51	58 ↑	55	21	20	21
Enbridge	35	38	39	48	56 ↑	54	20	19	21
Enbridge Gas	2	2	1	3	3	2	1	-	-
Hydro One	34	31	28	36	35	30	32	27 ↓	26
Toronto Hydro	12	8 ↓	9	15	11 ↓	9	10	5 ↓	9 ↑
Alectra	9	7	8	13	11	11	5	3	5
Ontario Hydro	9	7	8	10	8	9	7	6	6
Suncor	3	5	7	3	8 ↑	9	3	3	5
Union Gas	9	5 ↓	4	14	7 ↓	7	3	2	1
Enercare	6	4	4	6	5	5	5	3	4
Ottawa Hydro	5	4	4	7	5	6	3	2	3
Ontario Power Generation	4	3	3	4	3	3	3	3	2

↑↓ = significantly higher/lower versus the previous year at 95% confidence level *Note: Significant changes were made in 2021 (interpret shifts from 2020 to 2021 with caution)*

2020: Q1; Since 2021: Q2. When thinking of energy and energy infrastructure companies which come to mind?

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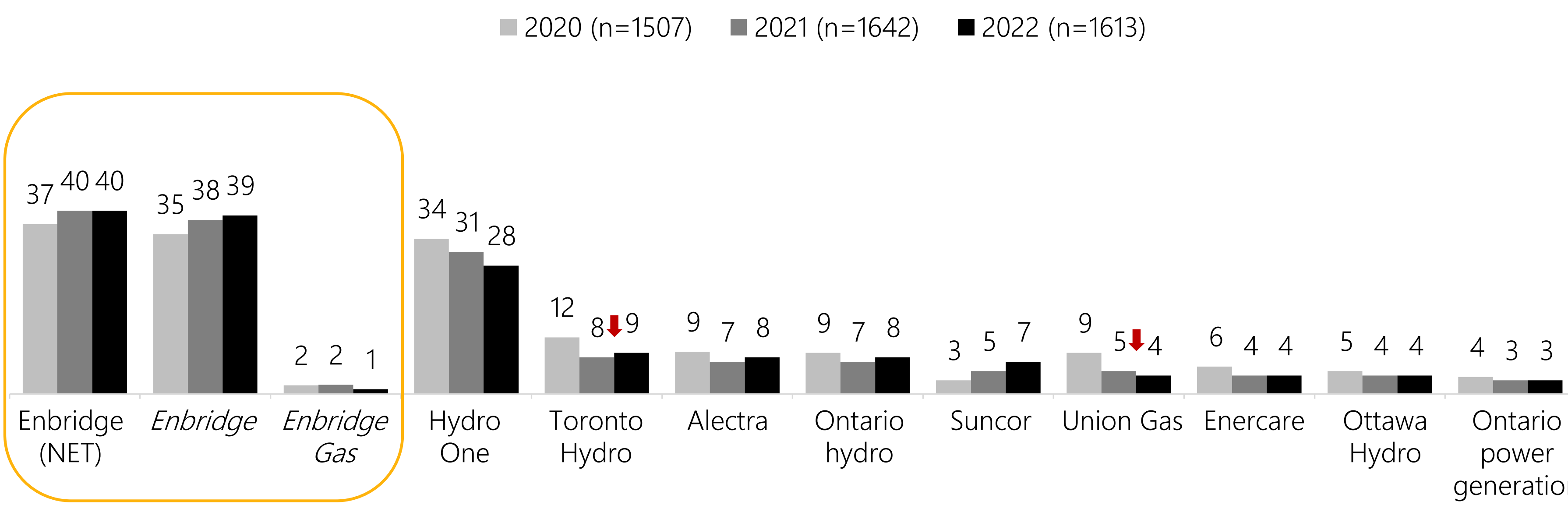
trend

unaided awareness of Enbridge remains stable over time

- A downward trend is noted for Hydro One.

unaided awareness – energy and energy infrastructure companies (%)



= significantly higher/lower versus the previous year at 95% confidence level *Note: Significant changes were made in 2021 (interpret shifts from 2020 to 2021 with caution)*

2020: Q1; Since 2021: Q2. When thinking of energy and energy infrastructure companies which come to mind?

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2022

Enbridge is more top of mind among males and respondents 55+ years of age

unaided awareness – energy and energy infrastructure companies (%)

		gender		age						community size	
	total	male	female	18-25	26+	18-34	35-54	55-64	65+	urban	non-urban
Base:	*1613*	*797*	*804*	*155*	*1458*	*444*	*495*	*321*	*353*	*732*	*881*
Enbridge (NET)	40	44	36	23	42	27	37	49	53	41	39
Hydro One	28	28	28	25	29	28	27	30	28	27	30
Toronto Hydro	9	11	8	9	9	11	11	7	5	15	4
Alectra	8	7	9	6	8	9	8	8	7	2	13
Ontario Hydro	8	8	7	1	8	1	6	12	14	8	7
Suncor	7	9	5	3	7	4	8	9	8	7	7
Union Gas	4	3	5	1	5	3	5	5	4	4	5

= significantly higher/lower versus the previous year at 95% confidence level

2020: Q1; Since 2021: Q2. When thinking of energy and energy infrastructure companies which come to mind?

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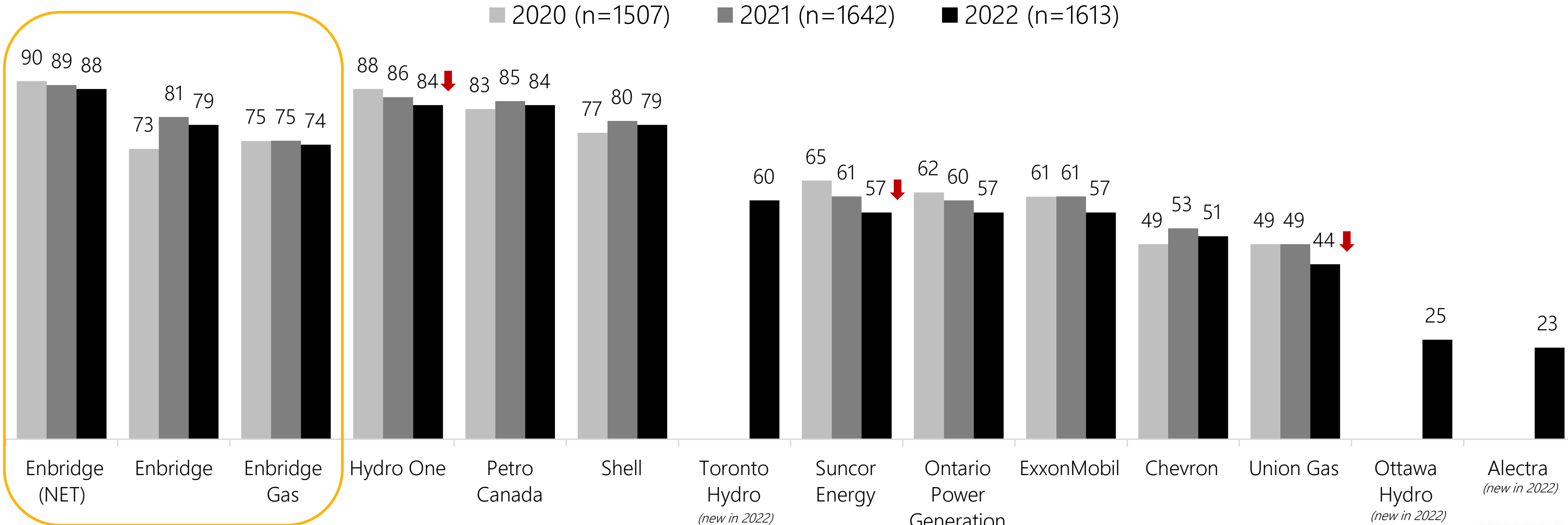
2022

highest aided awareness is for Enbridge (NET) followed by Hydro One and Petro Canada

- Aided awareness of Enbridge is stable since 2020 at about 9-in-10.
- Significant declines are noted for Hydro One, Suncor Energy, and Union Gas this year.

aided awareness of companies (%)



= significantly higher/lower versus the previous year at 95% confidence level

Q7. Which of these companies have you heard of? Please select all of the companies you have heard of, even if you may have already mentioned them in a previous question.

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trend

aided awareness of Enbridge is stable since 2020 at about 9-in-10

- Aided awareness for Enbridge has softened this year among customers, however results remain significantly higher versus 2020.
- Significant declines are noted for Hydro One, Suncor Energy, and Union Gas, driven by EGI non-customers.

aided awareness of companies (%)

	total			EGI customer			EGI non-customer		
	2020	**2021**	**2022**	**2020**	**2021**	**2022**	**2020**	**2021**	**2022**
Base:	*1507*	*1642*	*1613*	*785*	*864*	*893*	*722*	*778*	*720*
Enbridge (NET)	90	89	88	97	98	97	83	80	76
Enbridge	73	81 ↑	79	77	91 ↑	88 ↓	68	71	68
Enbridge Gas	75	75	74	83	86	85	66	63	59
Hydro One	88	86	84 ↓	92	90	90	84	82	77 ↓
Petro Canada	83	85	84	88	88	89	77	83 ↑	78 ↓
Shell	77	80 ↑	79	82	84	83	72	77 ↑	74
Toronto Hydro *(new in 2022)*	n/a	n/a	60	n/a	n/a	63	n/a	n/a	56
Suncor Energy	65	61 ↓	57 ↓	73	68 ↓	65	56	53	48
Ontario Power Generation	62	60	57	68	68	65	56	51	46 ↓
ExxonMobil	61	61	57	66	67	65	56	54	49 ↓
Chevron	49	53 ↑	51	53	61 ↑	57	44	45	44
Union Gas	49	49	44 ↓	59	56	53	39	42	33 ↓
Ottawa Hydro *(new in 2022)*	n/a	n/a	25	n/a	n/a	28	n/a	n/a	22
Alectra *(new in 2022)*	n/a	n/a	23	n/a	n/a	28	n/a	n/a	16

2020: Q5; Since 2021: Q7. Which of these companies have you heard of? Please select all the companies you have heard of, even if you may have already mentioned them in a previous question ↑↓ = significantly higher/lower versus the previous year at 95% confidence level
Removed in 2022: Bruce Power LP, Bullfrog Power, Epcor Utilities / Added in 2022: Toronto Hydro, Alectra, Ottawa Hydro

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2022

two-thirds report that Enbridge is a provider/ supplier/deliverer of natural gas

- Enbridge as a provider/supplier/deliverer of natural gas is mentioned more by EGI customers (78%) vs. non-customers (52%).
- Mentions of Enbridge building/maintaining energy infrastructure and being a provider of home heating/cooling increased this year.

perceptions of Enbridge (%)
among those aware of Enbridge (unaided)

TOP MENTIONS	total *1277*	EGI customer *788*	EGI non-customer *489*
Provides/supplies/delivers natural gas	68	78	52
Builds/maintains energy infrastructure	9 ↑	6 ↑	13 ↑
Home heating/cooling	8 ↑	8 ↑	10 ↑
Energy provider/utility company	6	5	7
Electricity	4	2	8
Oil/oil producer	4	4	4

↑↓ = significantly higher/lower versus the previous year at 95% confidence level

Q8A. Now please think about Enbridge. What exactly does Enbridge do?

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2022

4-in-10 think of Enbridge as an Ontario-based utility that delivers natural gas

- EGI customers are significantly more likely than non-customers to think of Enbridge as both an Ontario based utility and a leading North American energy infrastructure company (41% vs. 28%).

what comes to mind when thinking about Enbridge (%)
among those aware of Enbridge (aided)

	total *1277*	EGI customer *788*	EGI non-customer *489*
An Ontario-based utility that delivers natural gas to homes and businesses	42	41 ↓ (-6)	43
A leading North American energy infrastructure company whose core businesses include transporting oil and natural gas, distributing and storing natural gas, and renewable power generation	12	13	11 ↓ (-4)
Both of the above	36	41 ↑ (+6)	28
Other	0	0	0
None of these	8	4	16

↑↓ = significantly higher/lower versus the previous year at 95% confidence level

Q8B. When you think about Enbridge, what first comes to mind?

2022

over two-thirds report that Enbridge Gas is a provider/supplier/deliverer of natural gas

perceptions of Enbridge Gas (%)
among those aware of Enbridge Gas (unaided)

TOP MENTIONS	total *1189*	EGI customer *762*	EGI non-customer *427*
Provides/delivers/transports/supplies natural gas to Canadian households/businesses	73 ↑	79 ↑	62
Distribution/transportation/retail sale of LNG	13	13	12
Home heating/cooling	7	6	9
Pipeline-related/Energy infrastructure/Across Canada and USA	5	5	7

↑↓ = significantly higher/lower versus the previous year at 95% confidence level

Q9A. Now please think about Enbridge Gas. What exactly does Enbridge Gas do?

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2022

half of respondents think of Enbridge Gas as an Ontario-based utility that delivers natural gas

- By comparison, this is slightly higher than the proportion who think of Enbridge as an Ontario-based utility that delivers natural gas (42%).
- Similar to results for Enbridge, EGI customers are significantly more likely than non-customers to think of Enbridge Gas as both an Ontario based utility and a leading North American energy infrastructure (38% vs. 29%).

what comes to mind when thinking about Enbridge Gas (%)
among those aware of Enbridge Gas (aided)

	total *1189*	EGI customer *762*	EGI non-customer *427*
An Ontario-based utility that delivers natural gas to homes and businesses	48	47	50
A leading North American energy infrastructure company whose core businesses include transporting oil and natural gas, distributing and storing natural gas, and renewable power generation	11	11	10 ↓ (-4)
Both of the above	35	38	29
Other	1	0	1
None of these	6	3	11

↑↓ = significantly higher/lower versus the previous year at 95% confidence level

Q9B. When you think about Enbridge Gas, what first comes to mind?

Enbridge brand perceptions

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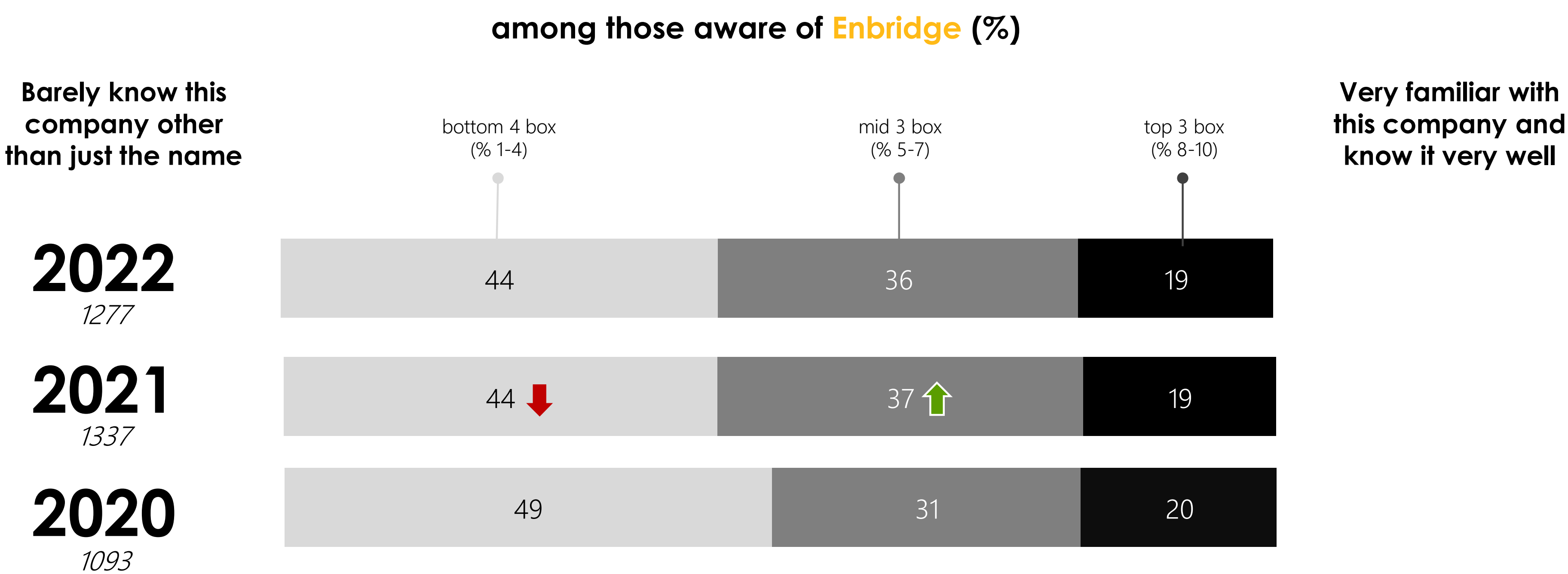
trend

familiarity with Enbridge

- Consistent with previous year's results, only 1-in-5 respondents feel very familiar with Enbridge (rating 8-10 out of 10).
- The proportion of respondents rating their familiarity with Enbridge 5-7 out of 10 and 1-4 out of 10 is on par with 2021.



= significantly higher/lower versus the previous year at 95% confidence level *Note: Significant changes were made in 2021 (interpret shifts from 2020 to 2021 with caution)*

2020: Q6a; Since 2021: B1: How well do you feel like you know Enbridge? Please place the red circle on the line where it best reflects your agreement with the statements on the left and right side of the scale. (Familiarity/Experience)

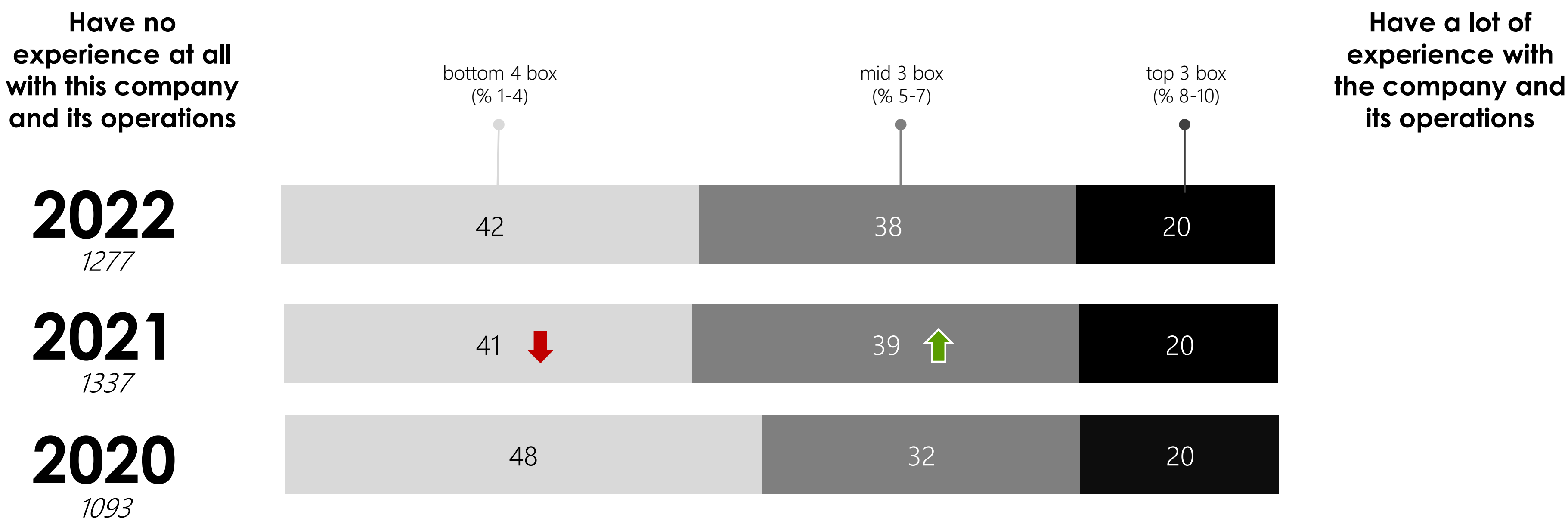
RESEARCH STRATEGY GROUP

trend

experience with Enbridge

- Similar to familiarity with Enbridge, only 1-in-5 respondents feel they have a lot of experience with Enbridge (rating 8-10 out of 10).
- The proportion of respondents who have had a moderate level of experience with Enbridge (5-7 out of 10) or have had little or no experience with Enbridge (1-4 out of 10) is also stable versus last year.

among those aware of Enbridge (%)



= significantly higher/lower versus the previous year at 95% confidence level *Note: Significant changes were made in 2021 (interpret shifts from 2020 to 2021 with caution)*
2020: Q6b; Since 2021: B2. How well do you feel like you know Enbridge? Please place the red circle on the line where it best reflects your agreement with the statements on the left and right side of the scale. (Familiarity/Experience)

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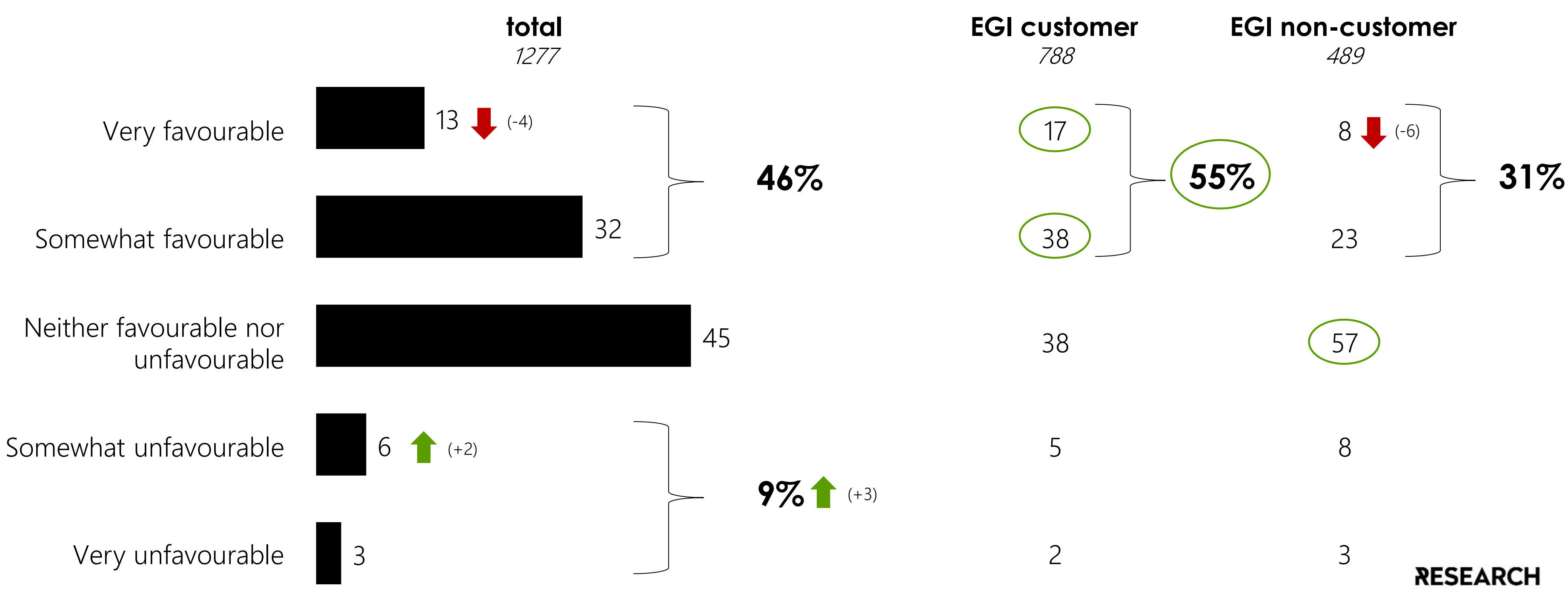
2022

overall opinion of Enbridge

- Nearly one-half of respondents have a favourable opinion of Enbridge – a decline in 'very favourable' responses is noted this year among EGI non-customers.
- As expected, EGI customers continue to have a significantly more favourable opinion of Enbridge (55% vs. 31%).

overall opinion (%)
among those aware of Enbridge



= significantly higher/lower versus the previous year at 95% confidence level

B3. Please indicate your overall opinion of Enbridge

trend

overall opinion of Enbridge

- After a significant increase in overall opinion of Enbridge (favourability) in 2021 among both EGI customers and EGI non-customers, results have stabilized in 2022.

overall opinion (%)
among those aware of Enbridge

	Total			EGI customer			EGI non-customer		
	2020	**2021**	**2022**	**2020**	**2021**	**2022**	**2020**	**2021**	**2022**
Base:	*1093*	*1337*	*1277*	*605*	*788*	*788*	*488*	*549*	*489*
Favourable (T2B)	34	48 ↑	46	42	57 ↑	55	23	35 ↑	31
Very favourable	8	17 ↑	13 ↓	12	20 ↑	17	4	14 ↑	8 ↓
Somewhat favourable	26	31 ↑	32	30	37 ↑	38	20	21	23
Neither favourable nor unfavourable	56	46 ↓	45	48	38 ↓	38	66	56 ↓	57
Somewhat unfavourable	8	4 ↓	6 ↑	7	3 ↓	5	9	6	8
Very unfavourable	2	2	3	2	1	2	2	2	3

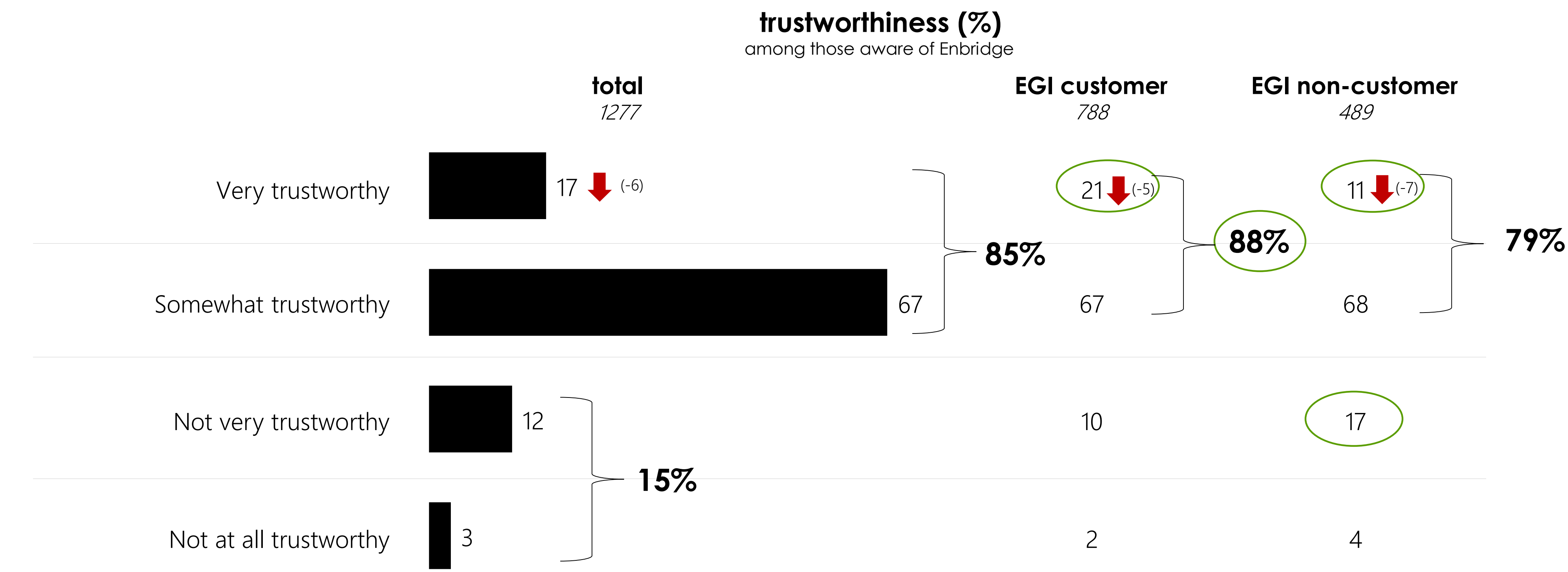
↑↓ = significantly higher/lower versus the previous year at 95% confidence level *Note: Significant changes were made in 2021 (interpret shifts from 2020 to 2021 with caution)*

2020: Q7; Since 2021: B3. Please indicate your overall opinion of Enbridge

2022

trustworthiness of Enbridge

- 85% of respondents find Enbridge trustworthy (very/somewhat).
  - A decline in 'very trustworthy' is noted this year, among both EGI customers and non-customers.
- EGI customers continue to be significantly more likely to find Enbridge trustworthy (88%) vs. non-customers (79%).



= significantly higher/lower versus the previous year at 95% confidence level

B6. Overall, how trustworthy do you find Enbridge?

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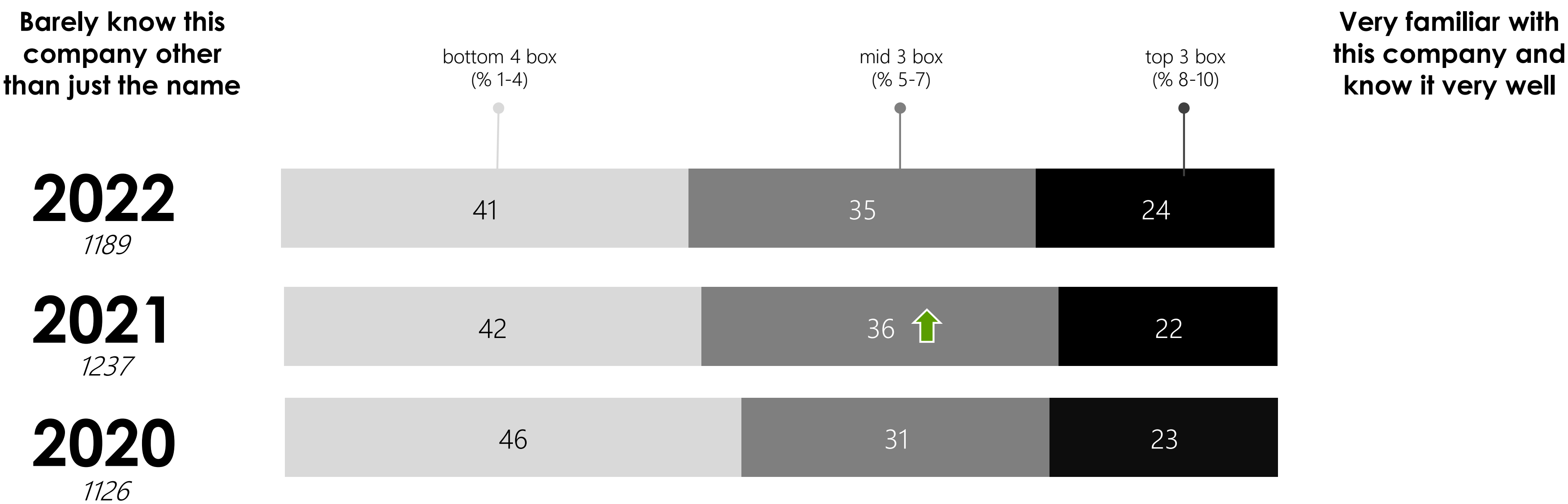
Enbridge Gas brand perceptions

trend

familiarity with Enbridge Gas

- Familiarity with Enbridge Gas has remained stable this year.
- Consistent with last year's results, only 24% feel very familiar with Enbridge Gas (rating 8-10 out of 10).

among those aware of Enbridge Gas (%)



= significantly higher/lower versus the previous year at 95% confidence level *Note: Significant changes were made in 2021 (interpret shifts from 2020 to 2021 with caution)*

2020: Q8a; Since 2021: B7: How well do you feel like you know Enbridge Gas? Please place the red circle on the line where it best reflects your agreement with the statements on the left and right side of the scale. (Familiarity/Experience)

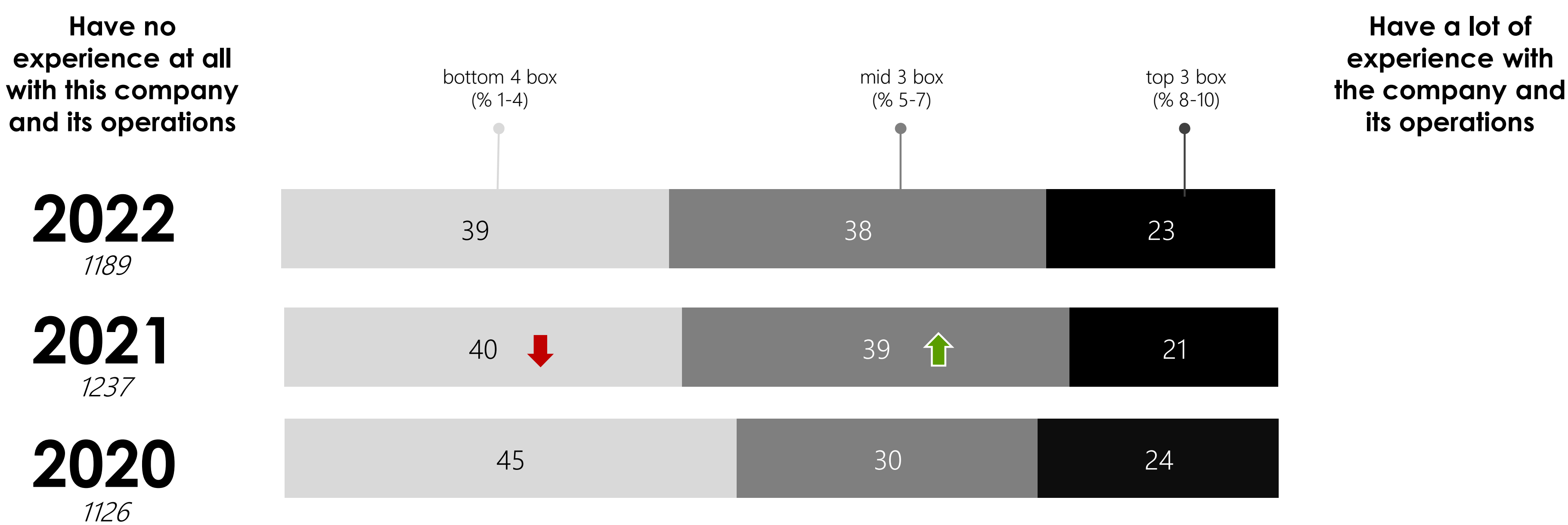
RESEARCH STRATEGY GROUP

trend

experience with Enbridge Gas

- The degree of experience with Enbridge Gas has also remained stable this year.

among those aware of Enbridge Gas (%)



= significantly higher/lower versus the previous year at 95% confidence level *Note: Significant changes were made in 2021 (interpret shifts from 2020 to 2021 with caution)*

2020: Q8b; Since 2021: B8. How well do you feel like you know Enbridge? Please place the red circle on the line where it best reflects your agreement with the statements on the left and right side of the scale. (Familiarity/Experience)

RESEARCH STRATEGY GROUP

2022

overall opinion of Enbridge Gas

- 48% of respondents have a favourable opinion of Enbridge Gas, while 7% have an unfavourable opinion.
- Declines in favourability are noted among both EGI customers and non-customers this year.

overall opinion (%)
among those aware of Enbridge Gas

	total *1189*		EGI customer *762*		EGI non-customer *427*	
Very favourable	14 ↓ (-3)	48%	18	55% ↓ (-5)	8 ↓ (-6)	34%
Somewhat favourable	33		37		27	
Neither favourable nor unfavourable	45		38		57	
Somewhat unfavourable	5	7%	5		6	
Very unfavourable	2		2		2	

↑↓ = significantly higher/lower versus the previous year at 95% confidence level
B9. Please indicate your overall opinion of Enbridge Gas

RESEARCH STRATEGY GROUP

trend

overall opinion of Enbridge Gas

- After significant improvement in overall opinion of Enbridge Gas in 2021, results have softened this year, with a significant decline in those 'very favourable' towards Enbridge Gas. However, overall opinion remains significantly higher compared to 2020 results.
- Declines in overall opinion are noted among both EGI customers and non-customers.

overall opinion (%)
among those aware of Enbridge Gas

	Total			EGI customer			EGI non-customer		
	2020	**2021**	**2022**	**2020**	**2021**	**2022**	**2020**	**2021**	**2022**
Base:	*1126*	*1237*	*1189*	*652*	*743*	*762*	*474*	*494*	*427*
Favourable (T2B)	34	51 ↑	48	44	60 ↑	55 ↓	21	37 ↑	34
Very favourable	8	17 ↑	14 ↓	12	20 ↑	18	2	14 ↑	8 ↓
Somewhat favourable	26	34 ↑	33	31	41 ↑	37	19	24	27
Neither favourable nor unfavourable	56	43 ↓	45	45	35 ↓	38	70	55 ↓	57
Somewhat unfavourable	7	4	5	8	3 ↓	5	7	5	6
Very unfavourable	3	1	2	3	1	2	2	2	2

↑↓ = significantly higher/lower versus the previous year at 95% confidence level *Note: Significant changes were made in 2021 (interpret shifts from 2020 to 2021 with caution)*
2020: Q9; Since 2021: B9. Please indicate your overall opinion of Enbridge Gas

RESEARCH STRATEGY GROUP

2022

main reasons for favourable opinions of Enbridge Gas are *reliable service* followed by no *difficulties experienced*

reasons for favourable opinions of Enbridge Gas (%)
among those with a favourable opinion

TOP MENTIONS	total 567	EGI customer 420	EGI non-customer 147
Provides good/reliable service	28 ↓	32 ↓	18
Have never experienced difficulties with the company	21 ↑	21	20 ↑
Renowned in the energy industry	7	6	9
Use for home gas/heating	7 ↑	7 ↑	5
Consistent/fast service delivery	6	7	4
Good customer service/support	6	7	4

↑↓ = significantly higher/lower versus the previous year at 95% confidence level
B10. You mentioned earlier that you have a favourable opinion towards Enbridge Gas. What is your main reason for this?

RESEARCH STRATEGY GROUP

2022

main reasons for favourable opinions of Enbridge Gas (a selection of verbatim responses)

PROVIDES GOOD/RELIABLE SERVICE

- "Canadian company, reliable, trustworthy."
- "I'm happy with the service they provide. When I've called them for anything they have been helpful."
- "They are a reliable company that delivers natural gas to my home."
- "Lived right close to one of their pipelines. They have been communicative, professional and provide assistance promptly."
- "Good customer service, no problems experienced with delivery of gas to my home."
- "Provide a good, reliable service. Care about people and the environment."

HAVE NEVER EXPERIENCED DIFFICULTY WITH THE COMPANY

- "I have never experienced an issue with Enbridge Gas before."
- "Used them for years and didn't have an issue with them except their prices got much higher."
- "Have never had a problem. Gas is always available."

RENOWNED IN THE ENERGY INDUSTRY

- "They have a good reputation for supply of gas and have had their services for over 30 years."
- "They are Canadian based, provide lots of good paying jobs, and are held to high environmental standards (compared to other oil and gas companies)."
- "Well established multinational company providing reliable quality service."

B10. You mentioned earlier that you have a favourable opinion towards Enbridge Gas. What is your main reason for this?

trend

the key reason for an unfavourable opinion of Enbridge Gas is *high costs*, with an increase in mentions of *rate increases* this year

reasons for unfavourable opinions of Enbridge Gas (%)

among those with an unfavourable opinion

TOP MENTIONS	total 89	EGI customer 53	EGI non-customer 36*
(NET) Cost/Overcharging/rate increases	57 ↑	75 ↑	31
Cost related/it is too expensive	52	66 ↑	31
Overcharges/rip their customers off	29	45 ↑	6
Too many rate increases in short period of time	11 ↑	15 ↑	6
(NET) Environmental concerns	19 ↓	6 ↓	39
Bad for the environment/destroying our planet/future of our children	12	4 ↓	25
Not environmentally conscious/not sustainable/not renewable	10	6	17
They don't seem to care about climate change	8	2 ↓	17
Terrible customer service	8	11	3
Pipeline protests	4	-	11

**Small base, interpret with caution* ↑↓ = significantly higher/lower versus the previous year at 95% confidence level

B11. You mentioned earlier that you have an unfavourable opinion towards Enbridge Gas. What is your main reason for this?

2022

main reasons for unfavourable opinions of Enbridge Gas (a selection of verbatim responses)

HIGH COST/OVERCHARGING/RATE INCREASES

- "They have the monopoly on the natural gas and charge an extravagant rate."
- "Delivery charges are more than the cost of gas. Too expensive!"
- "They dramatically increased their prices with barely any notice (my friends and family were impacted)."
- "My gas bill just went up $80 a MONTH, we are a two person household already conservative in energy usage."

LACK OF CONCERN FOR THE ENVIRONMENT

- "Enbridge Gas is a gas company. As a company that supplies fossil fuels, Enbridge is literally fueling the climate crisis. Enbridge also builds pipelines that damage the environment and Indigenous communities."
- "They are not doing enough to move us away from natural gas consumption."
- "Not a big fan of energy companies that have their main goal as exploiting natural resources in a non-renewable fashion. They're one of the leading causes of climate change. And they're profiting off it."

CUSTOMER SERVICE ISSUES

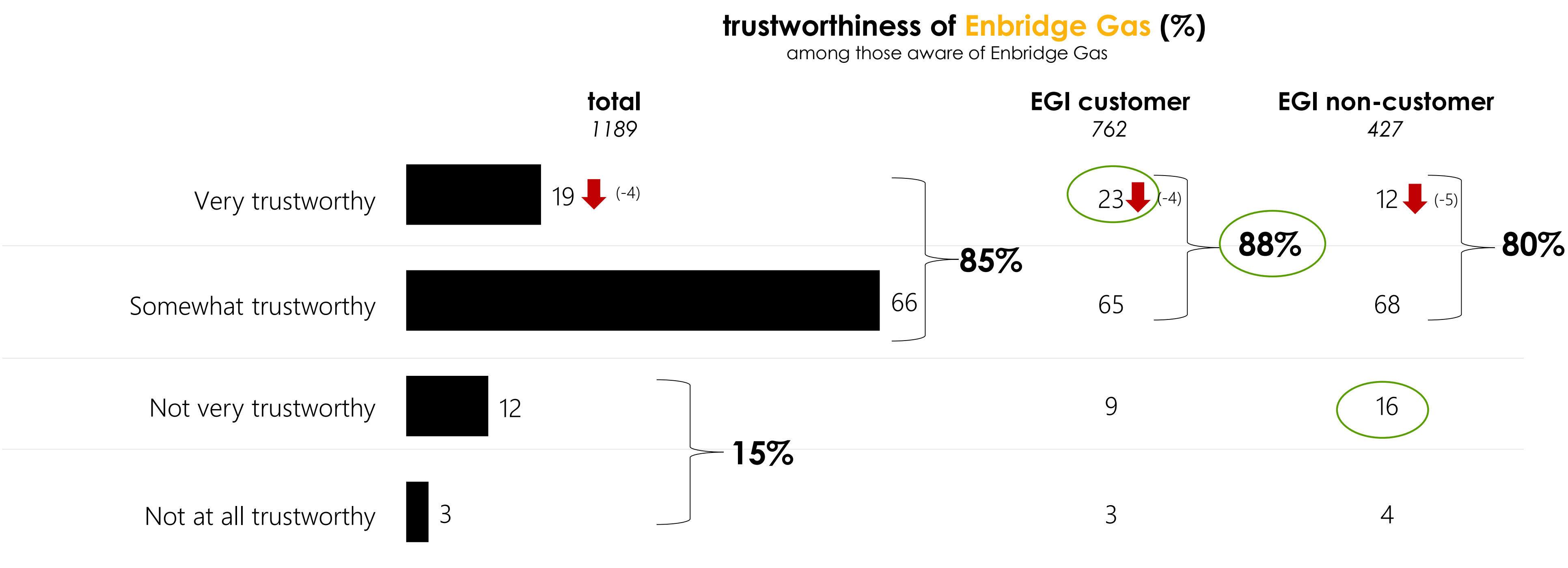
- "Their bills are not accurate. Their online bill payment and billing cycles are not customer friendly."
- "Rates keep fluctuating or increasing. Poor customer service and support."
- "Their prices have increased considerably, and their customer service leaves a lot to be desired. They have no low income support program like Hydro One and their equal monthly payments are not equal."

B11. You mentioned earlier that you have an unfavourable opinion towards Enbridge Gas. What is your main reason for this?

2022

trustworthiness of Enbridge Gas

- 85% of respondents find Enbridge Gas very/somewhat trustworthy – significantly higher among EGI customers (88% vs. 80%).
  - A decline in perceptions of Enbridge Gas being 'very trustworthy' is noted this year, among EGI customers and non-customers.



= significantly higher/lower versus the previous year at 95% confidence level
B12. Overall, how trustworthy do you find Enbridge Gas? (Question added in 2021)

RESEARCH STRATEGY GROUP

2022

trustworthiness of Enbridge Gas

- Respondents 55+ are more likely to find Enbridge Gas 'very trustworthy'.

trustworthiness of Enbridge Gas (%)
among those aware of Enbridge Gas

		customer		gender		age						community size	
	total	EGI	non-EGI	male	female	18-25	26+	18-34	35-54	55-64	65+	urban	non-urban
Base:	*1189*	*762*	*427*	*573*	*610*	*77*	*1112*	*264*	*367*	*268*	*290*	*527*	*662*
Trustworthy (T2B)	85	88	80	83	87	87	85	80	83	88	91	86	85
Very trustworthy	19	23	12	19	19	14	19	10	14	23	29	19	19
Somewhat trustworthy	66	65	68	64	69	73	66	69	69	65	63	67	66
Not very trustworthy	12	9	16	13	10	8	12	15	14	9	7	12	11
Not at all trustworthy	3	3	4	4	2	5	3	5	2	3	2	2	4

B12. Overall, how trustworthy do you find Enbridge Gas? (Question added in 2021)

RESEARCH STRATEGY GROUP

2022

comparison of brand perception metrics (Enbridge vs. Enbridge Gas)

- Enbridge and Enbridge Gas perform on par across key brand perception metrics.

comparison of brand perceptions (%)
among those aware of Enbridge and Enbridge Gas

		Total		EGI customer		EGI non-customer	
		Enbridge	Enbridge Gas	Enbridge	Enbridge Gas	Enbridge	Enbridge Gas
		1277	1189	788	762	489	427
familiarity	Top 3 box (% 8-10)	19	24	26	30	10	13
experience	Top 3 box (% 8-10)	20	23	27	30	10	11
overall opinion (favourability)	Very/somewhat favourable	46	48	55	55	31	34
	Neither	45	45	38	38	57	57
	Very/somewhat unfavourable	9	7	7	7	11	8
trustworthiness	Top 2 box (%) (very/somewhat)	85	85	88	88	79	80

RESEARCH STRATEGY GROUP

how innovative is Enbridge Gas

2022 (new)

- Older respondents are more likely to find Enbridge Gas innovative.

how innovative is Enbridge Gas (%)
among those aware of Enbridge Gas

		customer		gender		age						community size	
	total	**EGI**	**non-EGI**	**male**	**female**	**18-25**	**26+**	**18-34**	**35-54**	**55-64**	**65+**	**urban**	**non-urban**
Base:	*1218*	*779*	*439*	*590*	*622*	*77*	*1141*	*270*	*375*	*274*	*299*	*540*	*678*
Innovative (T2B)	74	75	71	73	75	77	74	70	68	78	80	72	75
Very innovative	10	11	8	9	11	6	10	7	11	10	12	10	10
Somewhat innovative	64	64	63	63	64	70	63	64	57	68	68	63	64
Not very innovative	23	22	24	23	22	18	23	25	27	19	18	24	21
Not at all innovative	4	3	5	4	3	5	4	4	5	3	2	3	4

B13. Overall, how innovative do you find Enbridge Gas? (Question added in 2022)

RESEARCH STRATEGY GROUP

how sustainable is Enbridge Gas

2022 (new)

- EGI customers are more likely to perceive Enbridge Gas as sustainable.

how sustainable is Enbridge Gas (%)
among those aware of Enbridge Gas

		customer		gender		age						community size	
	total	EGI	non-EGI	male	female	18-25	26+	18-34	35-54	55-64	65+	urban	non-urban
Base:	*1218*	*779*	*439*	*590*	*622*	*77*	*1141*	*270*	*375*	*274*	*299*	*540*	*678*
Sustainable (T2B)	73	77	65	73	72	58	74	57	70	78	86	72	73
Very sustainable	16	19	11	17	16	12	17	10	12	19	25	16	16
Somewhat sustainable	56	58	54	56	56	47	57	47	58	59	61	55	57
Not very sustainable	23	20	28	21	25	32	22	34	25	19	12	23	23
Not at all sustainable	5	3	8	6	4	9	5	9	5	3	2	6	4

B14. Overall, how sustainable do you find Enbridge Gas? (Question added in 2022)

RESEARCH STRATEGY GROUP

trend

comparison of brand perception metrics (Enbridge vs. Enbridge Gas)

		total						EGI customer						EGI non-customer					
		Enbridge			Enbridge Gas			Enbridge			Enbridge Gas			Enbridge			Enbridge Gas		
		2020	2021	2022	2020	2021	2022	2020	2021	2022	2020	2021	2022	2020	2021	2022	2020	2021	2022
		1039	1337	1277	1126	1237	1189	605	788	788	652	743	762	488	549	489	474	494	427
		%	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%
familiarity	Top 3 box (% 8-10)	20	19	19	23	22	24	25	24	26	31	27	30	14	12	10	12	16	13
experience	Top 3 box (% 8-10)	20	20	20	24	21	23	28	25	27	34	27 ↓	30	11	12	10	10	12	10
overall opinion (favour-ability)	Very/somewhat favourable	34	48 ↑	46	34	51 ↑	48	42	57 ↑	55	44	60 ↑	55 ↓	23	35 ↑	31	21	37 ↑	34
	Neither	56	46 ↓	45	56	43 ↓	45	48	38 ↓	38	45	35 ↓	38	66	56 ↓	57	70	55 ↓	57
	Very/somewhat unfavourable	10	6 ↓	9 ↑	10	6 ↓	7	10	5 ↓	7 ↑	11	5 ↓	7 ↑	11	8	77	9	7	7
trust-worthiness	Top 2 box (%) (very/somewhat)	n/a	87	85	n/a	87	85	n/a	90	88	n/a	90	88	n/a	83	79	n/a	83	80
innovative	Top 2 box (%) (very/somewhat)	n/a	n/a	n/a	n/a	n/a	74	n/a	n/a	n/a	n/a	n/a	75	n/a	n/a	n/a	n/a	n/a	71
sustainable	Top 2 box (%) (very/somewhat)	n/a	n/a	n/a	n/a	n/a	73	n/a	n/a	n/a	n/a	n/a	77	n/a	n/a	n/a	n/a	n/a	65

↑↓ = significantly higher/lower versus the previous year at 95% confidence level

Note: Significant changes were made in 2021 (interpret shifts from 2020 to 2021 with caution)

RESEARCH STRATEGY GROUP

2022

comparison of key metrics by subgroups

		total	EGI customer	EGI non-customer	18-25	26+	18-34	35-54	55-64	65+
		%	%	%	%	%	%	%	%	%
Unaided awareness of Enbridge/Enbridge Gas (NET)		40	55	21	23	42	27	37	49	53
Aided awareness of Enbridge/Enbridge Gas (NET)		88	97	76	26	67	41	65	75	74
Enbridge *(only asked of those aware)*										
Familiarity	Top 3 box (% 8-10)	19	26	10	16	20	17	20	18	21
Experience	Top 3 box (% 8-10)	20	27	10	15	21	17	23	19	21
Favourability	Very/somewhat favourable	46	55	31	36	47	35	44	51	54
Trustworthiness	Very/somewhat trustworthy	85	88	79	85	85	79	81	88	91
Enbridge Gas *(only asked of those aware)*										
Familiarity	Top 3 box (% 8-10)	24	30	13	21	24	22	23	24	28
Experience	Top 3 box (% 8-10)	23	30	11	19	23	17	25	23	26
Favourability	Very/somewhat favourable	48	55	34	49	48	38	45	51	56
Trustworthiness	Very/somewhat trustworthy	85	88	80	87	85	80	83	88	91
Innovative	Very/somewhat innovative	74	75	71	77	74	70	68	78	80
Sustainable	Very/somewhat sustainable	73	77	65	58	74	57	70	78	86

RESEARCH STRATEGY GROUP

2022

Enbridge Gas is most strongly associated with essential and reliable

- Association of other brand attributes with Enbridge Gas is more muted.

EGI brand attribute association (%)

	total *1613*	EGI customer *893*	EGI non-customer *720*
Essential	51	63	37
Reliable	51	64	35
Expensive	38	45	30
Trustworthy	23	27	17
Sustainable	20	25	15
Competitive	17	18	15
Technical	15	15	14
Innovative	12	14	9
Something else	3	2	4
None of these	14	5	25

B13. Now we would like you to think about Enbridge Gas, the company that delivers natural gas to homes in Ontario. Please look at the list of words below and indicate which of these you associate with Enbridge Gas? *Note: No trending available as significant revisions were made to the list of attributes in 2022.*

RESEARCH STRATEGY GROUP

2022

Older respondents are more likely to associate Enbridge Gas with being *essential, reliable* and *expensive*

EGI brand attribute association (%)

	total	gender		age						community size	
	total 1613	male 797	female 804	18-25 155	26+ 1458	18-34 444	35-54 495	55-64 321	65+ 353	urban 732	non-urban 881
Essential	51	53	50	37	53	41	49	57	63	49	53
Reliable	51	54	49	32	53	35	47	63	66	50	52
Expensive	38	35	42	24	40	30	42	42	41	37	40
Trustworthy	23	24	22	26	22	19	18	26	30	23	22
Sustainable	20	21	20	20	20	14	17	23	29	20	20
Competitive	17	19	15	22	16	16	14	17	21	19	15
Technical	15	16	13	17	14	14	12	14	20	16	14
Innovative	12	13	11	17	11	11	10	13	13	13	11
Something else	3	3	3	3	3	3	2	3	3	3	3
None of these	14	13	15	23	13	22	15	10	7	14	14

B13. Now we would like you to think about Enbridge Gas, the company that delivers natural gas to homes in Ontario. Please look at the list of words below and indicate which of these you associate with Enbridge Gas? Note: Significant revisions made to the list of attributes in 2022.

RESEARCH STRATEGY GROUP

2022

Enbridge Gas is most strongly associated with being a natural gas storage/distribution company

- Additionally, EGI customers are more likely to think of Enbridge Gas as a leader in the provision and distribution of energy, a top employer in Ontario and with excellent customer service.

Enbridge Gas perceptions (%)

	total *1613*	**EGI customer** *893*	**EGI non-customer** *720*
A natural gas storage and distribution company	58	70	43
A leader in the provision and distribution of energy	31	41	20
A top employer in Ontario	18	20	15
Excellent customer service	15	20	10
Has higher energy costs compared to other energy companies	15 ↑ (+4)	16 ↑ (+3)	13 ↑ (+3)
A leader in energy conservation *(2021: A leader in environmental conservation and protection)*	11 ↑ (+4)	12 ↑ (+4)	10
An essential partner in the transition to net zero emissions *(2021: A leader in the transition to net zero emissions)*	11 ↑ (+5)	13 ↑ (+7)	8
Has more environmental impacts compared to other energy companies	9	10	8
A company with new inventions, ideas, and technology	8	9	7
A leader in the creation and provision of green tech	5	5	5
None of these	20	11	30

↑↓ = significantly higher/lower versus the previous year at 95% confidence level

B14. Still thinking about Enbridge Gas, which of the following, if any, do you associate with Enbridge Gas.

RESEARCH STRATEGY GROUP

perceptions of natural gas

2022

Natural gas continues to be seen as having many roles as a fuel source

- Most commonly, natural gas is seen as a practical alternative to oil and electricity, as well as easily accessible and the best option for my home, with perceptions generally stable since last year.

natural gas is…(%)

	total *1613*	EGI customer *893*	EGI non-customer *720*
A practical alternative to oil	42	49	32
A practical alternative to electricity	34	39	27
Easily accessible	31	41	20
The best energy option for my home	28	41	11 ↓ (-4)
The most reliable energy source	23	31	13
The only energy source I need to heat my home	21	31	9
Not prone to shortages in supply	18	24	11 ↓ (-4)
The most affordable energy option[1]	19	24	12
An energy source for the future	19	21	16
An environmentally friendly energy option	19	21 ↑ (+4)	16
An essential energy option for moving to net zero emissions by 2050	14	16	11
The safest energy option	12	14	8 ↓ (-4)
Other	2	2	3
None of these	17	10	26

[1] Prior to 2022: The most economical energy option

↑↓ = significantly higher/lower versus the previous year at 95% confidence level

N1. Now we would like you to think about natural gas in general. What do you see as the role of natural gas as a fuel source today? Natural gas is....

2022

natural gas will continue to have a role in the future as a necessary back up to solar and wind and an alternative to other fossil fuels

natural gas will be...(%)

	total *1613*	EGI customer *893*	EGI non-customer *720*
A necessary backup to solar or wind power	39 ↑ (+4)	46 ↑ (+7)	31
An alternative to other fossil fuels	38	42	34
The best energy option to heat my home	26 ↓ (-3)	35	14 ↓ (-7)
Replaced by other sources of energy	23 ↑ (+4)	24 ↑ (+4)	21
The most reliable energy option	20 ↓ (-6)	26 ↓ (-7)	14 ↓ (-6)
An increasingly clean energy source	19 ↑ (+5)	22 ↑ (+8)	16
A more expensive energy option	17 ↑ (+7)	19 ↑ (+9)	15 ↑ (+5)
The most affordable energy option[1]	16 ↓ (-7)	19 ↓ (-7)	13 ↓ (-6)
Other	2	1	3
None of these	13	7	21

[1] Prior to 2022: The most economical energy option

N2. What do you see as the role of natural gas as an energy source in the future? Natural gas will be... ↑↓ = significantly higher/lower versus the previous year at 95% confidence level

2022

natural gas use is expected to remain the same over the next 5 years

- Nearly three-quarters expect their use of natural gas to remain the same over the next 5 years – higher among EGI customers.

natural gas use in the next 5 years (%)
among those currently using natural gas

	total *1134*	EGI customer *893*	EGI non-customer *241*
My use of natural gas will increase	15	14	19
My use of natural gas will stay the same	71	73	62
My use of natural gas will decrease	14	13	19

= significantly higher/lower versus the previous year at 95% confidence level
N3. Which of the following best describes how you expect to use natural gas in the next 5 years?

RESEARCH STRATEGY GROUP

2022

new appliances, more people in household and moving to a larger residence are top reasons for expected increase in natural gas usage

reasons for expected natural gas use increase (%)
among those who say it will increase

	total *172*	EGI customer *126*	EGI non-customer *46**
I will be purchasing more appliances that use natural gas	36	41	22 (-28)
The number of people in my house will increase	21	21	22
I will be moving to a larger residence	17	16	22
I will be replacing an existing fuel source with natural gas	17	13	26
I will be buying a second residence/cottage/home	12	11	13
Other	26	28	20

**small base, interpret with caution*
= significantly higher/lower versus the previous year at 95% confidence level
N4. Why do you think your use of natural gas will increase in the next 5 years? Please select all that apply.

RESEARCH STRATEGY GROUP

2022

those expecting to decrease their use will do so by adopting more energy efficient practices and making their home more energy efficient

reasons for expected natural gas use decrease (%)
among those who say it will decrease

	total *159*	EGI customer *113*	EGI non-customer *46**
I will adopt more energy efficient practices like turning down the thermostat, wearing sweaters, etc.	48	47	50
I will be taking steps to make my residence more energy efficient	41	45	30
I plan to purchase more efficient appliances	30	30	28
I will be switching to a different energy source for heating like electricity	24	25	22
I will be switching to a higher efficiency heating system	21	21	22
The number of people in my household will decrease	18	19	13
Moving to a home that does not use natural gas	14	12	17
Moving to a smaller home	13	9 ⬇ (-10)	24
Selling a second residence/cottage/home	4	4	2
Other	7	5	11

**small base, interpret with caution*
⬆⬇ = significantly higher/lower versus the previous year at 95% confidence level
N5. Why do you think your use of natural gas will decrease in the next 5 years? Please select all that apply.

RESEARCH STRATEGY GROUP


ensuring a
sustainable future

2022 (new)

Roughly one-quarter are aware of energy conservation programs for homes/businesses – awareness of other initiatives is low

things Enbridge Gas is doing to ensure a sustainable energy future – awareness (%)

	total *1613*	EGI customer *893*	EGI non-customer *720*
Enbridge Gas offering energy conservation programs for homes and businesses to help them use less energy and reduce carbon emissions	26	34	15
Enbridge Gas' commitment to achieving net zero emissions in its own operations by 2050	14	16	11
Enbridge Gas leading Ontario's transition to a cleaner energy future	14	17	10
Enbridge Gas partnering with municipalities and others to convert heavy transportation vehicles like trucks and busses to zero and low-carbon technologies like compressed natural gas and renewable natural gas	13	15	11
Enbridge Gas greening the natural gas supply with carbon-neutral renewable natural gas generated from waste, and hydrogen	10	12	7
Enbridge Sustain, a new line of business providing homeowners, businesses and builders with turnkey solutions with no upfront costs for low carbon technologies like geothermal, solar, and hybrid heating	7	8	6
Opt Up, a program through which customers can contribute to the purchase of renewable natural gas generated from waste, to green the gas supply	5	5	5
None of these	54	46	63

T2. Here is a list of things that Enbridge Gas is doing to help ensure a sustainable energy future. Please select the ones that you were aware of before today. Please select all that apply.

RESEARCH STRATEGY GROUP

2022

Encouragingly, two-thirds are interested in finding out more about at least one program being offered

- Note: question wording and some answer options were revised this year.

things Enbridge Gas is doing to ensure a sustainable energy future – most interested (%)

	total *1613*	EGI customer *893*	EGI non-customer *720*
Enbridge Gas offering energy conservation programs for homes and businesses to help them use less energy and reduce carbon emissions	36 ↓ (-5)	44 ↓ (-5)	26 ↓ (-7)
Enbridge Gas' commitment to achieving net zero emissions in its own operations by 2050	29	32	26
Enbridge Sustain, a new line of business providing homeowners, businesses and builders with turnkey solutions with no upfront costs for low carbon technologies like geothermal, solar, and hybrid heating *(new in 2022)*	28	33	22
Enbridge Gas greening the natural gas supply with carbon-neutral renewable natural gas generated from waste and hydrogen	26 ↓ (-7)	29 ↓ (-6)	22 ↓ (-8)
Enbridge Gas leading Ontario's transition to a cleaner energy future	26	31	20
Enbridge Gas partnering with municipalities and others to convert heavy transportation vehicles like trucks and busses to zero and low-carbon technologies like compressed natural gas and renewable natural gas	25 ↓ (-5)	27 ↓ (-5)	21 ↓ (-5)
Opt Up, a program through which customers can contribute to the purchase of renewable natural gas generated from waste, to green the gas supply *(Opt Up reference added 2022)*	19	22	16
None of these	32 ↑ (+8)	28 ↑ (+10)	38 ↑ (+8)

↑↓ = significantly higher/lower versus the previous year at 95% confidence level

T1. Once again, here is a list of things that Enbridge Gas is doing to help ensure a sustainable energy future. Please select the ones that are most interesting to you and would like to learn more about. Please select all that apply. *Note: Revisions made to the question wording and answer options in 2022.*

RESEARCH STRATEGY GROUP

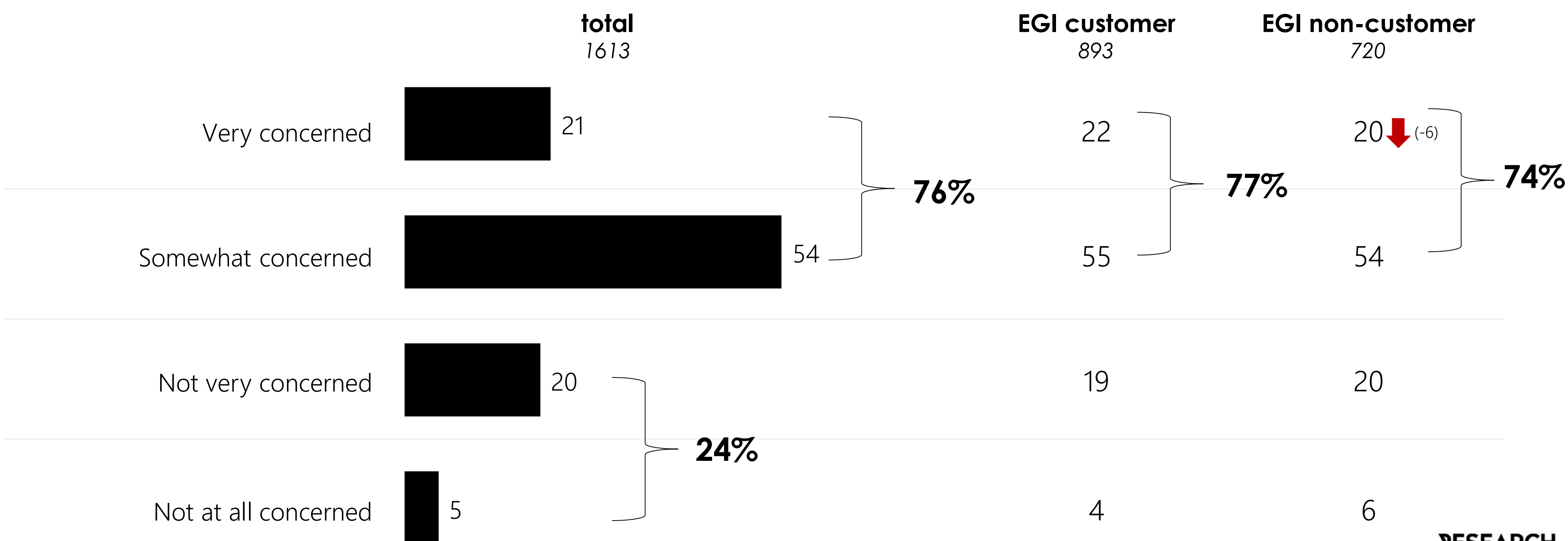

environmental
concerns

2022

three-quarters of respondents indicate they are concerned about how the energy they use is generated

- Females are significantly more likely to be concerned about how the energy they use is generated (79% vs. 72% very/somewhat).

concern about energy generation (%)



G1. Some people are very concerned about how the energy they use is generated (e.g. coal, hydroelectric, nuclear, solar, wind), while others are not concerned about this at all. How do you feel about how the energy you use is generated? Are you ... ⬆⬇ = significantly higher/lower versus the previous year at 95% confidence level

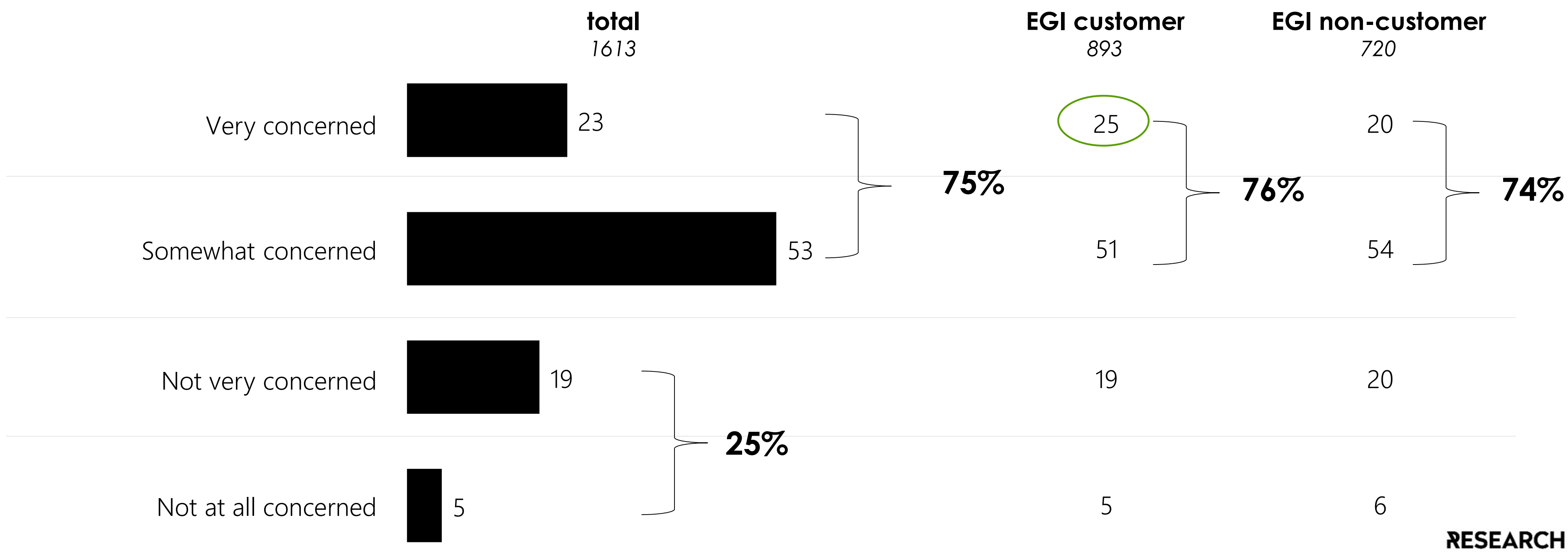
RESEARCH STRATEGY GROUP

2022

three-quarters of respondents indicate they are concerned with where energy they use <u>comes from</u>

- Similar to energy generation, female respondents are significantly more likely to be concerned about where the energy they use comes from compared to male respondents (78% vs. 73% very/somewhat).

concern about energy source (%)



G2. Some people are very concerned about where the energy they use comes from (e.g. locally, within Ontario, within Canada, from the U.S.), while others are not concerned about this at all. How do you feel about where the energy you use comes from? Are you … ⬆⬇ = significantly higher/lower versus the previous year at 95% confidence level

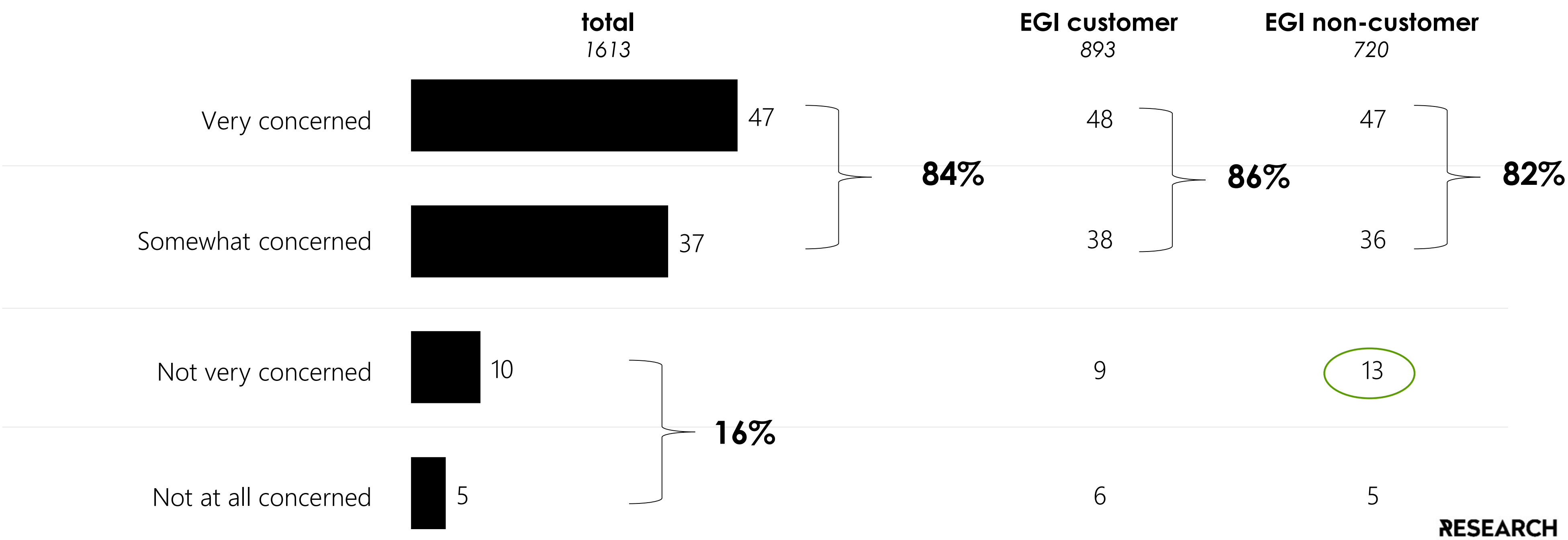
RESEARCH STRATEGY GROUP

2022

84% of respondents indicate they are concerned about climate change

- Women are also more concerned about climate change (52% are very concerned vs. 43% among men).
- Respondents 65+ and urban residents are also more likely to be very concerned.

concern about climate change (%)



= significantly higher/lower versus the previous year at 95% confidence level

G3. Some people are very concerned about climate change, while others are not concerned about this at all. How do you feel about climate change? Are you …

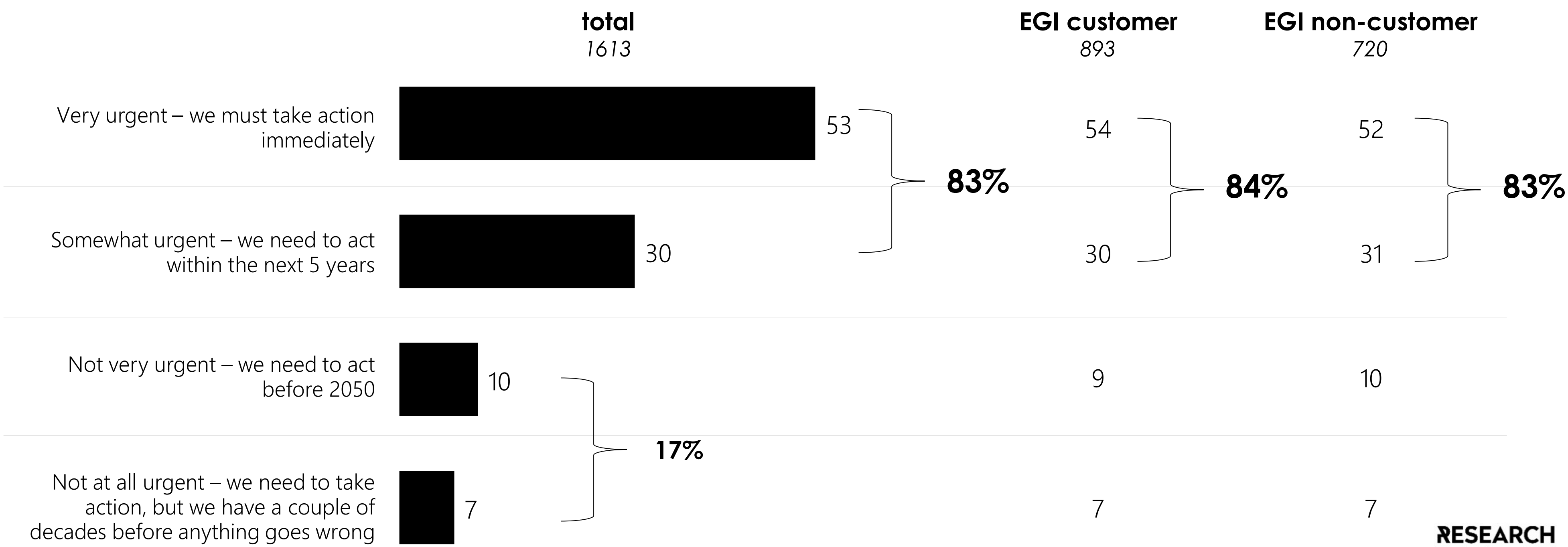
RESEARCH STRATEGY GROUP

2022

53% indicate a very urgent need for action on climate change

- Women also feel action on climate change is more urgent (88% very/somewhat urgent vs. 79% among men).

urgency of action on climate change (%)



= significantly higher/lower versus the previous year at 95% confidence level

G4. How urgent do you consider the need for action on climate change?

RESEARCH STRATEGY GROUP

appendix

RESEARCH STRATEGY GROUP

2022

total sample

49 AVERAGE AGE

49% MALE

50% FEMALE

$105,200 AVERAGE HHI

45% URBAN

55% RURAL

home status %

Own home	39
Mortgage	27
Rent	20

72% HOUSE

25% CONDO/APT

role in energy related HH decisions %

7 NO ROLE

47 SOLE

45 SHARED

19% HH WITH CHILDREN < 18

Adults in HH %

26 THREE+

25 ONE

48 TWO

employment %

Employed	65
Retired	26
Unemployed	3

education %

HS or less	10
College	32
University+	56

EGI customers

52 AVERAGE AGE

52% MALE

47% FEMALE

$114,300 AVERAGE HHI

42% URBAN

58% RURAL

home status %

Own home	48
Mortgage	33
Rent	11

89% HOUSE

9% CONDO/APT

role in energy related HH decisions %

4 NO ROLE

47 SOLE

49 SHARED

22% HH WITH CHILDREN < 18

Adults in HH %

27 THREE+

18 ONE

54 TWO

employment %

Employed	65
Retired	30
Unemployed	1

education %

HS or less	9
College	31
University+	60

EGI non-customers

45 AVERAGE AGE

46% MALE

OTHER 1%

53% FEMALE

$93,400 AVERAGE HHI

49% URBAN

51% RURAL

home status %

Own home	28
Mortgage	19
Rent	31

52% HOUSE

43% CONDO/APT

role in energy related HH decisions %

11 NO ROLE

48 SOLE

41 SHARED

16% HH WITH CHILDREN < 18

Adults in HH %

25 THREE+

32 ONE

40 TWO

employment %

Employed	65
Retired	22
Unemployed	4

education %

HS or less	13
College	34
University+	51

questionnaires

Questionnaire 2020

Questionnaire 2021

Questionnaire 2022

RESEARCH STRATEGY GROUP

global market research

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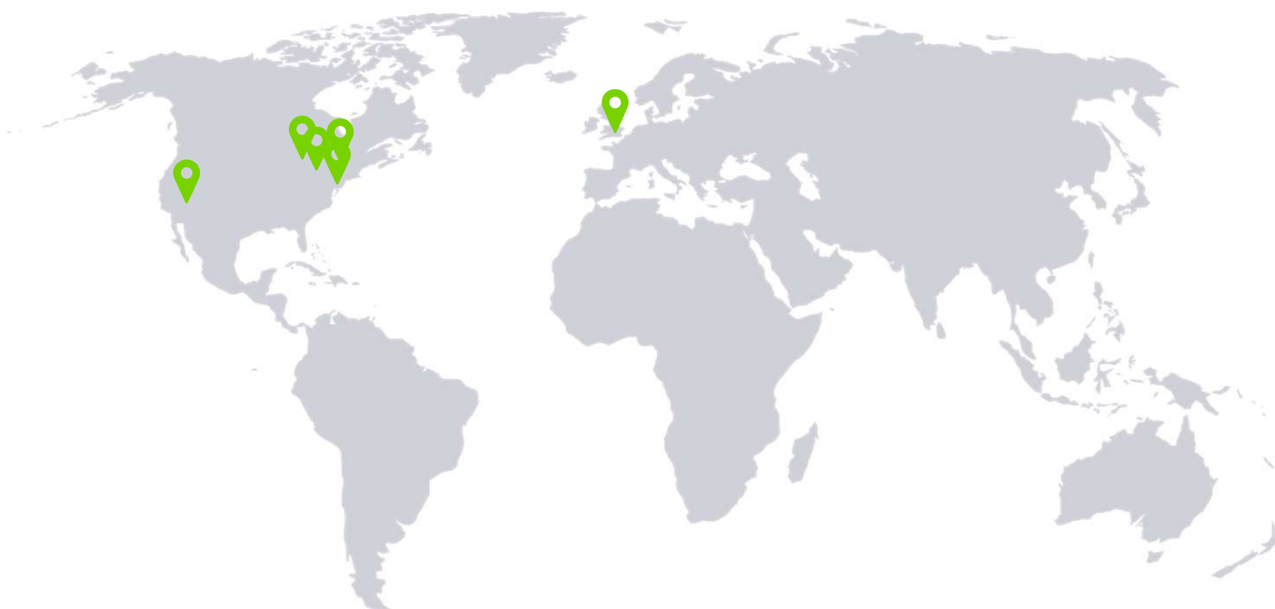


GRIT 2021 TOP 50 INNOVATIVE COMPANY

Enbridge Gas Brand Pulse Survey
Wave 1

A survey of legacy Union Gas residential customers to gauge their awareness of the amalgamation

September 23, 2019

ENBRIDGE®

Zulfiqar Ali
Advisor Market Research,
Market Research and Analysis

Survey Objective

- The objective of this pulse survey was to estimate awareness of the utility amalgamation among Legacy Union Gas residential customers, as well as awareness that Union Gas will be known as Enbridge going forward.

- The information is expected to be used to help determining appropriate timing for removing the Union Gas logo from remaining residential customer communications such as the bill and website.

- A second wave of the survey (to provide an updated "pulse") will be executed as needed.

Survey Contents

ENBRIDGE

1 Un-aided Awareness of Gas Provider Name

2 Aided familiarity with the amalgamation

3 If familiar:

- sources of familiarity

4 If not familiar:

- Preferred channels to receive information about Enbridge Gas

5 Opportunity to pass along any comments or suggestions

6 Demographics: respondent age

Survey Methodology

The main survey was completed by telephone. In parallel, an online survey was used to investigate the group of customers that receive email communications from Enbridge. Details of the methodology for the two surveys are summarized below.

Telephone Survey	Online Survey (Qualtrics)
• Customers were randomly selected for the survey from the entire population of Legacy Union Gas residential customers. • A randomly selected group of 400 customers was interviewed. • Telephone interviews were conducted during August 13-29, 2019. • Due to the randomness of the sample, the survey results are representative of the total legacy Union Gas residential customer population. The associated margin of error is +/- 4.9%.	• Customers were randomly selected for the survey from a list of all Legacy Union Gas residential customers with an email address on file (the majority are paperless billing customers or have a myaccount profile). • 15,000 email survey invitations were sent during August 16 -25, 2019. • 566 customers completed the survey. • Results are not generalizable to the total Legacy Union Gas customer population since only customers with email addresses on file were eligible.

Summary of Findings

- About one-third of legacy Union Gas (LUG) residential customers are aware that the company that delivers natural gas to their home is now Enbridge Gas. LUG bill and LUG bill inserts are the stated key sources of information about the merger.

- For customers who were not familiar with the merger, emails and natural gas bill inserts are by far the most preferred stated sources of important information like the merger.

- Level of customer awareness is significantly influenced by billing service type (paperless billing, APP, EBP). Those who are on paperless billing, APP, or EBP are found relatively less aware of the merger.

- When invited to pass along any comments or suggestions the respondents felt important to share with Enbridge Gas, customers expressed high level of satisfaction with the service they had received from LUG in the past and expected similar service moving forward.

1. Un-aided Awareness

What is the name of the company that delivers natural gas to your home?

Telephone Survey

Base = 400

Enbridge	Union Gas	Other *	Don't Know
32%	48%	10%	10%

Online Survey (Qualtrics)

Base = 566

Enbridge	Union Gas	Other *	Don't Know
42%	53%	4%	1%

****"Other" included:** Reliance; Entegrus; Enwin; Hydro One; Reliance Home Comfort; Union Energy; Reliance; Halton Hills Hydro; hamilton hydro; Festival Hydro; GSU; Lakefront Utilities; Erth Power; Entregus; Encana; Northern gas.*

About one-third of customers are aware that the company that delivers natural gas to their home is now Enbridge Gas *(Telephone Survey)*

1. Un-aided Awareness by billing service

ENBRIDGE

What is the name of the company that delivers natural gas to your home?
(% that correctly identified Enbridge as their natural gas provider)

Bill Type	Automatic Payment Plan (APP)	Equal Billing Plan (EBP)
Paper bill = 44% Paperless = 26%	APP = 26% Non-APP = 39%	EBP = 32% Non-EBP = 44%

Source: Telephone survey (Similar pattern for the online survey).

Level of customer awareness is significantly influenced by billing service type

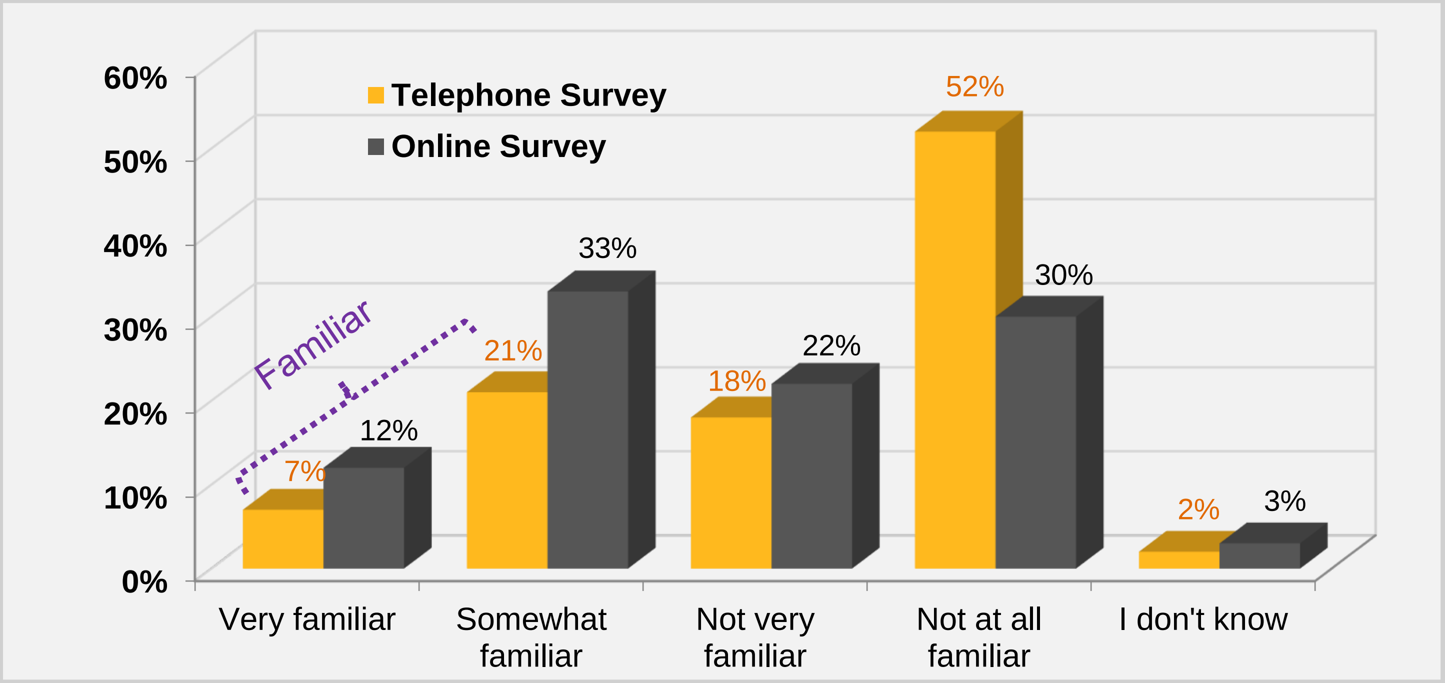
2. Aided Familiarity

The survey respondents were read the following statement and then asked the familiarity question.

"AS OF JANUARY 1, 2019, UNION GAS AND ENBRIDGE GAS DISTRIBUTION HAVE AMALGAMATED INTO ONE UTILITY WITH THE LEGAL NAME ENBRIDGE GAS INC. UNION GAS WILL TRANSITION TO THE ENBRIDGE NAME OVER TIME"

Before today, how familiar were you with the Union Gas and Enbridge Gas merger?

Very familiar
Somewhat familiar
Not very familiar
Not at all familiar
Don't know



	Telephone Survey	Online Survey
Total Familiar	**52% ***	**45%**

** Calibrated to total base (=400) for the telephone survey. That is, including those who answered "Enbridge" to the un-aided awareness question "What is the name of the company that delivers natural gas to your home?"*

About one-half of customers said they were familiar (aided) with the merger

3. Stated Sources of Familiarity

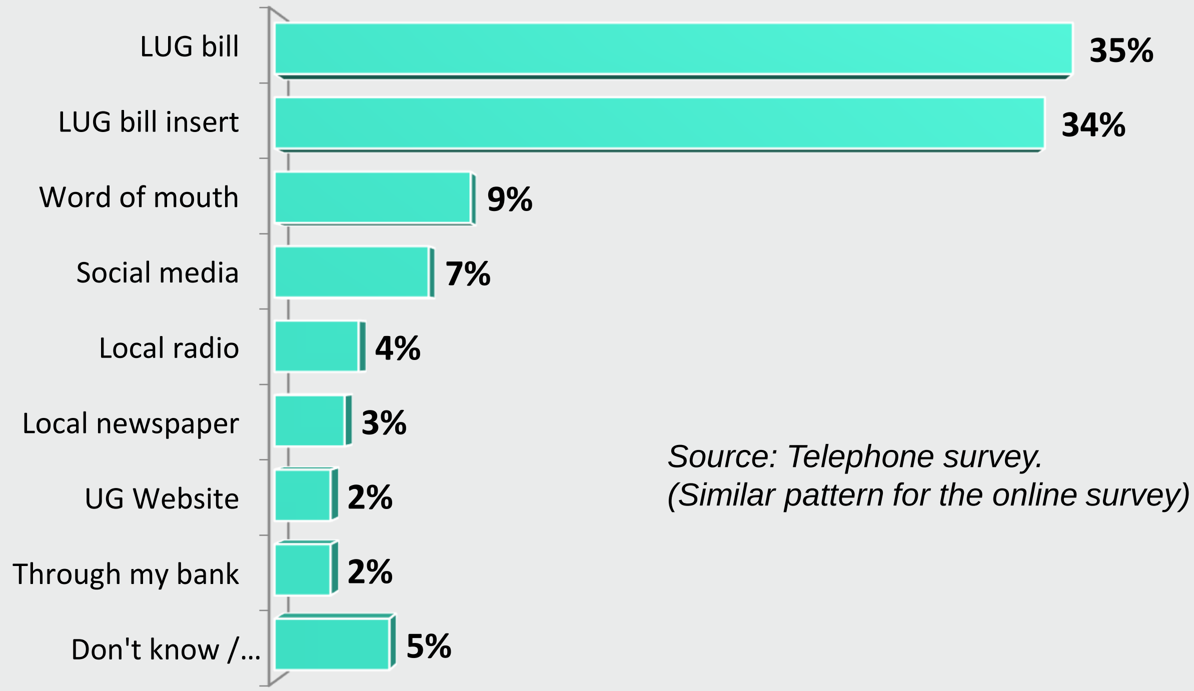
ENBRIDGE

Before today, how familiar were you with the Union Gas and Enbridge Gas merger?

- Very familiar
- Somewhat familiar
- Not very familiar
- Not at all familiar
- Don’t know

Base: Those familiar

How did you first hear about the Union Gas and Enbridge Gas merger?



Source: Telephone survey.
(Similar pattern for the online survey)

The Legacy Union Gas bill and bill inserts are the key stated sources of information about the amalgamation.

4. Stated Communication Preferences

Before today, how familiar were you with the Union Gas and Enbridge Gas merger? (*Base = 400)*

Very familiar

Somewhat familiar

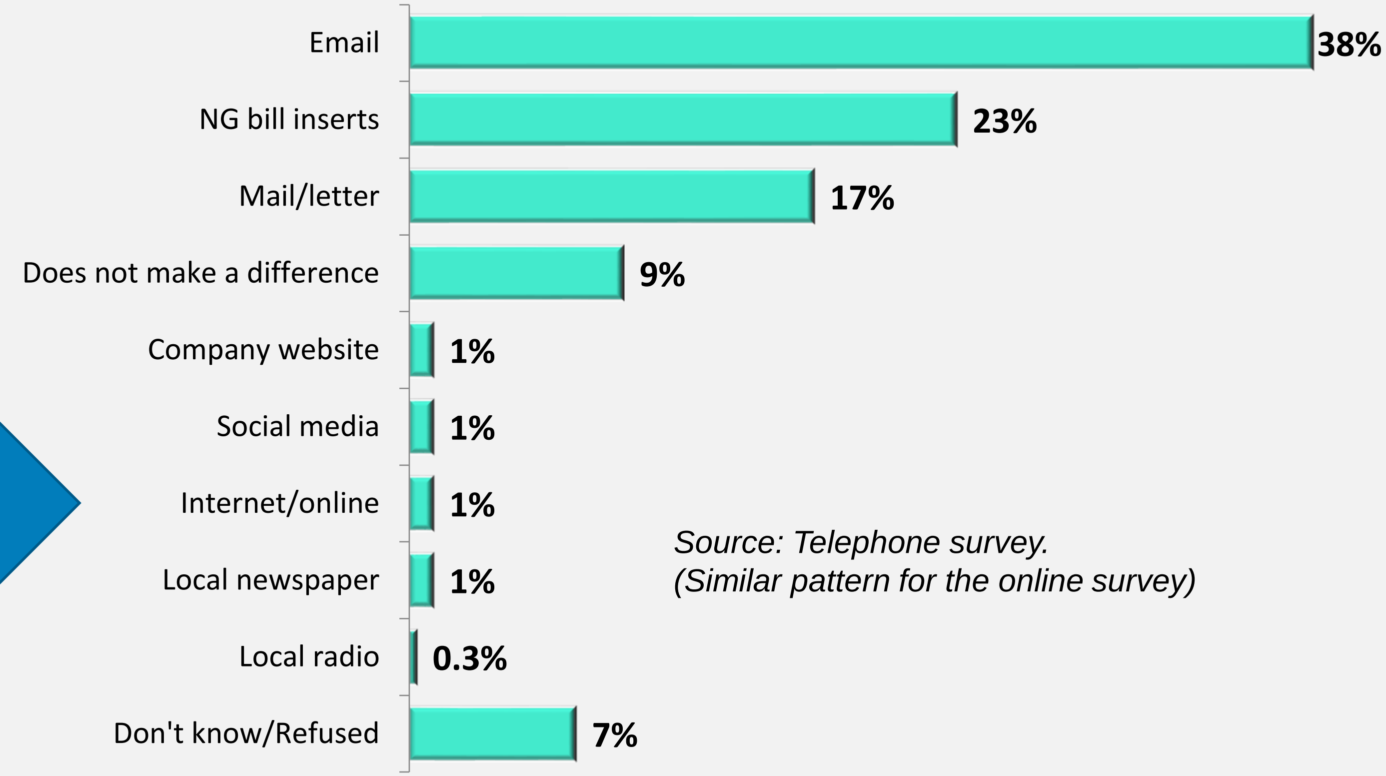
Not very familiar

Not at all familiar

Don't know

Those who were not familiar

How would you prefer your natural gas delivery company to provide you important information like Union Gas and Enbridge Gas merger?



Source: Telephone survey.
(Similar pattern for the online survey)

Emails are by far the most preferred sources of information by customers

5. Customer Comments or Suggestions

Finally, you have an opportunity to pass along any comments or suggestions that you feel are important to share with Enbridge Gas. Do you have any final comments?

"Thanks for the great service over the years!"

"Hydro One could learn a lot from you …"

"I have nothing but excellent service from Union Gas. They are eager to assist when called and that is greatly appreciated"

"Enbridge has big shoes to fill …."

"Fix your website, I can't login to my account since the merger has taken place"

"Is Enbridge a Canadian company "

"Now with the merger, and shared resources, the costs would surely decrease. It would be great if you could pass some of that savings to customers"

"We appreciate always trying to improve your company so you can pass it along to your customers"

"Continue strong PR program that natural gas is more environmentally friendly and more transparency regarding gas leaks etc. And what detection and safeguards are in place to keep consumers safe"

"I hope I get the same service I got with Union from Enbridge. We converted to gas from electric and service from *Union gas was very good"

"I just wanted to thank you guys for your service and everything you have done for me and my family. Maybe its not safe for the environment, but its more economical"

"I think Enbridge could do a better job maintaining and should honor contracts like when they make deals with the first nations and Matie"

"I'm very comfortable with them I signed a new contract with them this year they are pretty good"

"not satisfied with the merger---hope that because of this merger my gas will not go up"

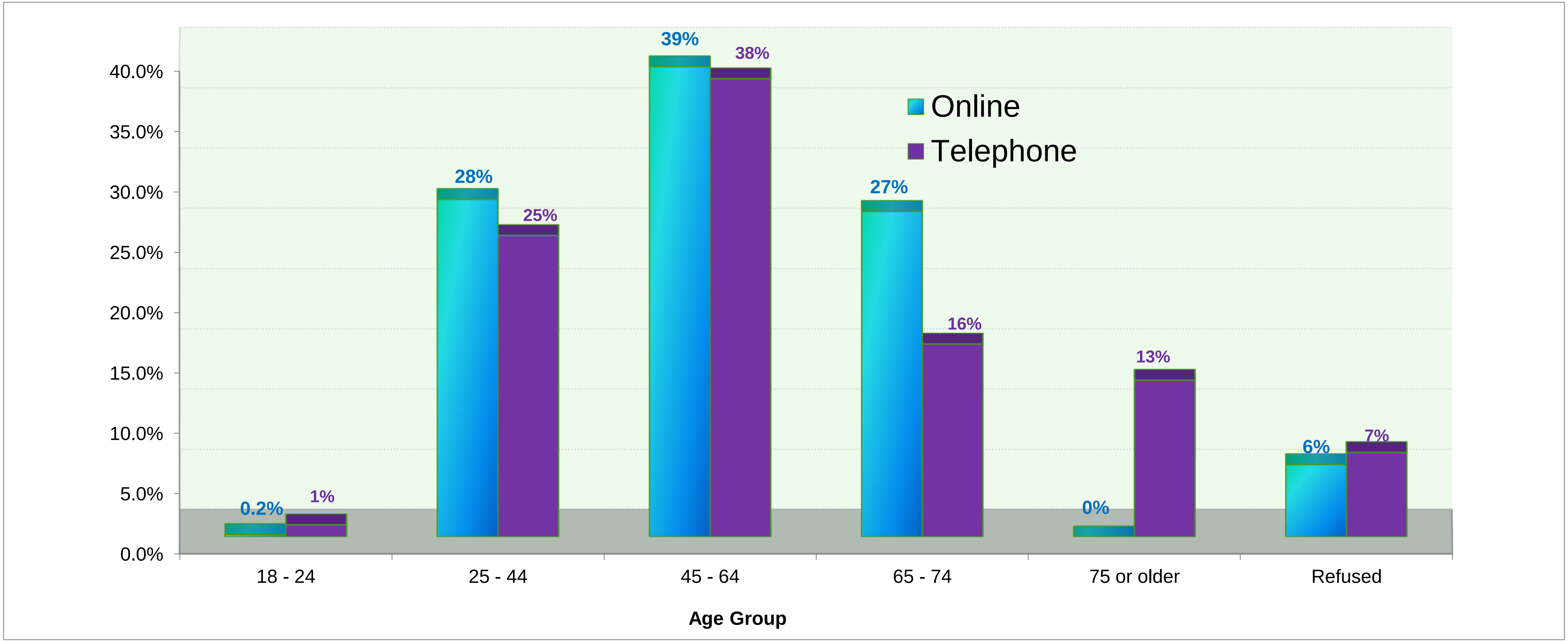
"Now they are a merger they are a monopoly , they should keep our prices down their overhead down if they have the money to merger why are they always at the board asking for price increases"

"Will there be any price increase as a result of the merger?"

"with this merger i hope the gas bill doesn't goes up"

Customers expressed satisfaction with the service they received in the past and expect similar service moving forward

6. Age Distribution of Survey Respondents



Appendix

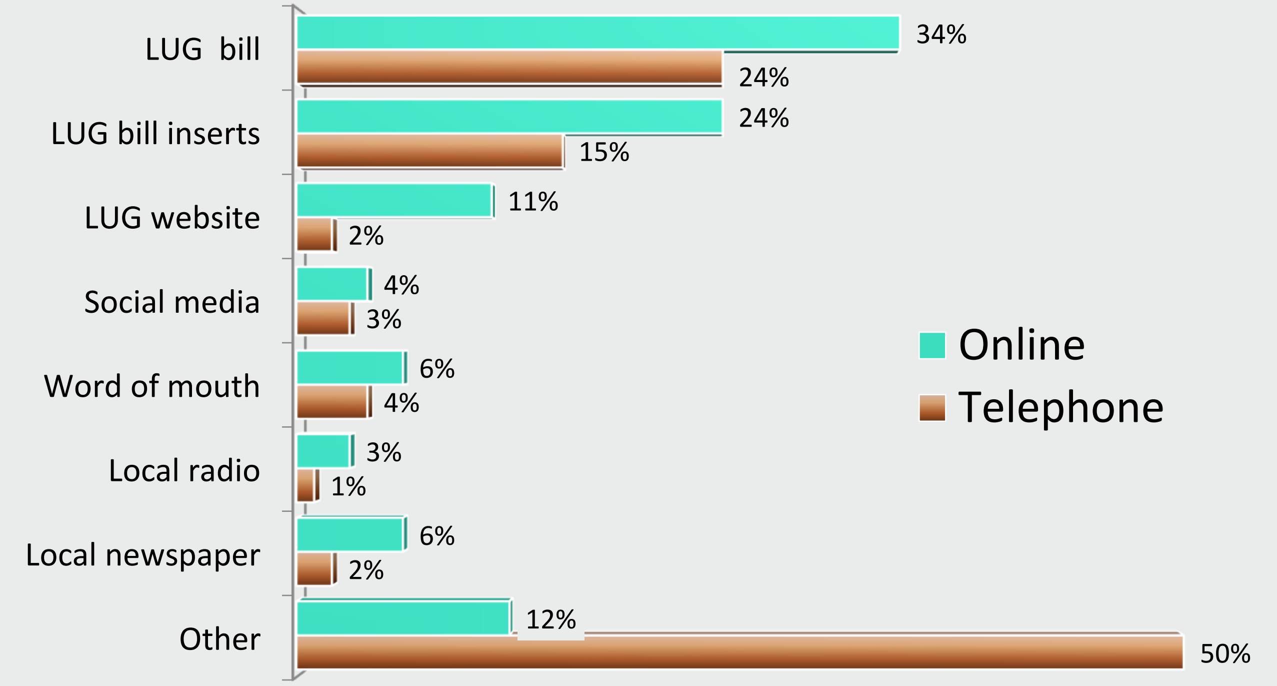
Stated Sources of Familiarity

Before today, how familiar were you with the Union Gas and Enbridge Gas merger?

- Very familiar
- Somewhat familiar
- Not very familiar
- Not at all familiar
- Don't know

Base: Those familiar

How did you first hear about the Union Gas and Enbridge Gas merger?



Legacy Union Gas bill, Bill inserts, and the Website are the top-3 stated sources of information about the merger

Stated Communication Preferences

ENBRIDGE

Before today, how familiar were you with the Union Gas and Enbridge Gas merger?
(Base = 400)

Very familiar

Somewhat familiar

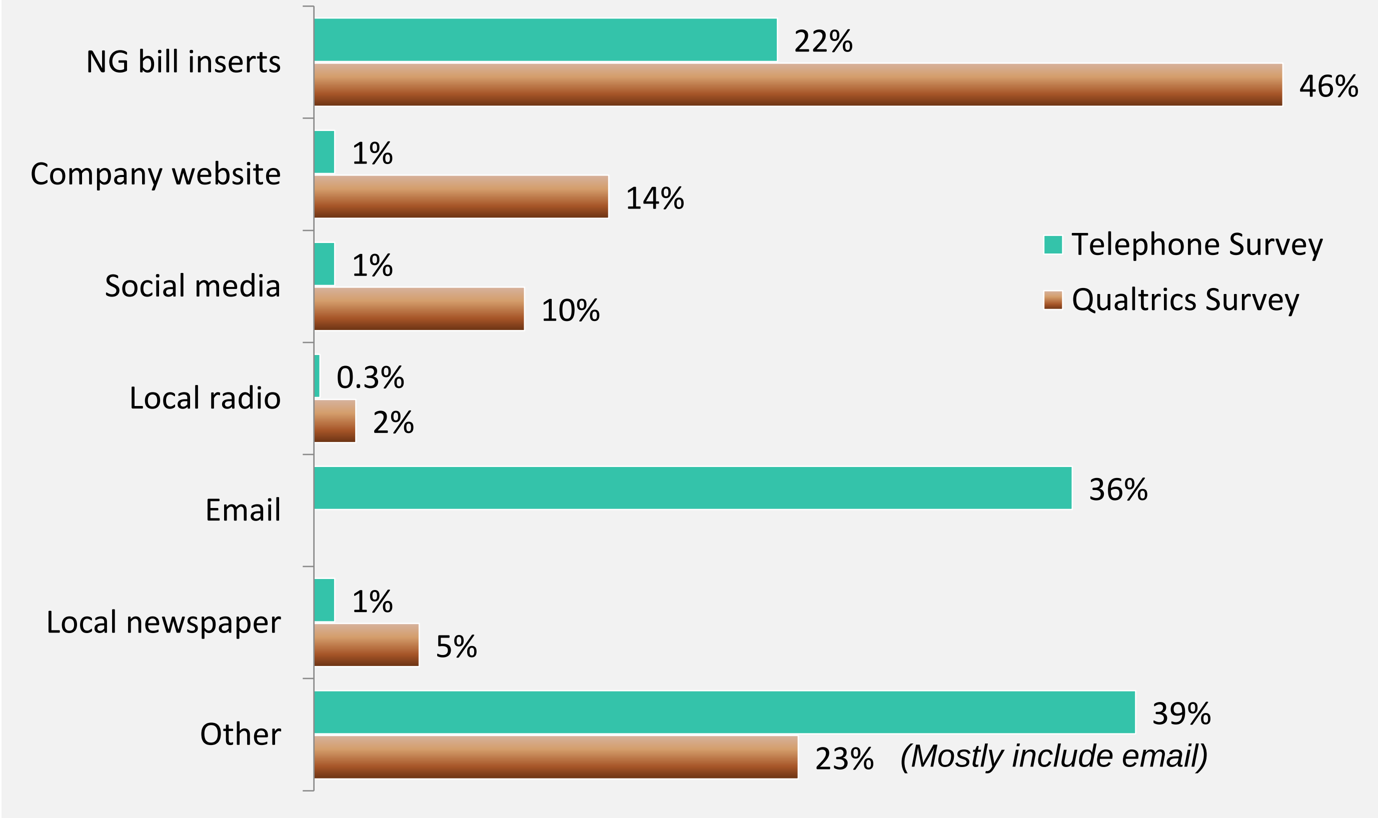
Not very familiar

Not at all familiar

Don't know

Those who were not familiar

How would you prefer your natural gas delivery company to provide you important information like Union Gas and Enbridge merger?



Natural gas bill inserts are by far the most popular source of important information like Union Gas and Enbridge merger

2022 SAFETY AWARENESS & COMPLIANCE SURVEY

December 2022

Contents

METHODOLOGY & OBJECTIVES

Methodology & Objectives

The purpose of this research initiative is to track awareness, understanding and behaviours related to natural gas safety over time.

More specifically, the research tracks attitudes and behaviours as it relates to:

1. Heating equipment & maintenance;
2. Natural gas safety;
3. Cross-bore awareness;
4. Carbon monoxide alarms & safety; and,
5. Safety communications.

Overall, n=1,200 natural gas users completed the online survey between November 15 and 28, 2022. Within this core sample, n=600 natural gas users who live within the boundaries of legacy Union Gas territory and n=600 natural gas users who live within the boundaries of legacy Enbridge Gas Distribution territory were surveyed. Consistent with the previous year, non-Enbridge Gas Inc. natural gas users have been included in the sample as it was determined that it is important to survey and inform all natural gas users who live in the Enbridge service territory about natural gas safety topics, regardless of who their natural gas service provider is.

Throughout the report, there is tracking against data from the 2019, 2020 and 2021 surveys. Green arrows ⬆ identify statistically significant increases and red arrows ⬇ denote statistically significant decreases, relative to 2021. Green circles ○ identify statistically significant increases and red circles ○ denote statistically significant decreases, relative to 2020.

Survey results have been weighted by age, gender, region, bill type (eBill vs. paper bill), and respondent type (legacy Enbridge vs. legacy Union Gas) to ensure that the sample is representative of the target population. Where totals do not add to 100%, it is due either to rounding or the respondent was permitted to provide more than one response. For more details on weighting, please see the appendix section.

KEY FINDINGS & EXECUTIVE SUMMARY

Key Findings

1. There is an overwhelming belief that it is safe to use natural gas.

2. Many natural gas users in the Enbridge service territory might be less knowledgeable about natural gas safety than they think they are, though some behaviours are improving.

3. There is a somewhat common misperception that carbon monoxide alarms are also capable of detecting natural gas leaks.

4. There is growing awareness of the need to get a line locate, before digging.

5. Safety information recall across most metrics remains consistent with 2021, though continues to track mostly below what was observed in earlier years.

Executive Summary

The vast majority (89%) of natural gas users believe it is safe to use natural gas in homes and most feel as though they are at least moderately knowledgeable about all natural gas safety topics, save for blocked sewer lines. And yet as the objective measures of this survey indicate, natural gas users in the Enbridge service territory might be a little less knowledgeable about natural gas safety than they think they are.

The results of this survey postulate that there might be some knowledge gaps, when it comes to natural gas safety, among natural gas users who live in the Enbridge service territory. As evidenced by the natural gas safety knowledge test, many appear to be unclear on matters such as laws relating to carbon monoxide alarms, the frequency with which natural gas appliances need to be inspected, or even whether they (or their contractor) need to call before digging.

Additionally, there are some concerning misperceptions that continue to persist regarding natural gas safety and carbon monoxide alarms. Similar to what has been observed in previous years, a sizeable proportion of natural gas users believe carbon monoxide alarms are also capable of detecting natural gas leaks. In fact, the proportion that erroneously believe their carbon monoxide alarm is also capable of detecting natural gas leaks has increased, year-over-year (30%; +5 pts vs. 2021). When asked how they would know if they had a natural gas leak as many as three in ten (31%) aren't worried about this because they say they have a carbon monoxide alarm, a figure which underscores how uninformed many natural gas users are when it comes to their carbon monoxide alarms and natural gas safety, more generally.

Executive Summary (cont.)

While natural gas users might be a little less knowledgeable about natural gas safety than they think they are, there has been improvement over time on some metrics, in the safety behaviours of natural gas users in the Enbridge service territory. This suggests that the natural gas safety initiatives taken by Enbridge Gas Inc. might have had a positive effect on certain natural gas safety behaviours of users in their service territory.

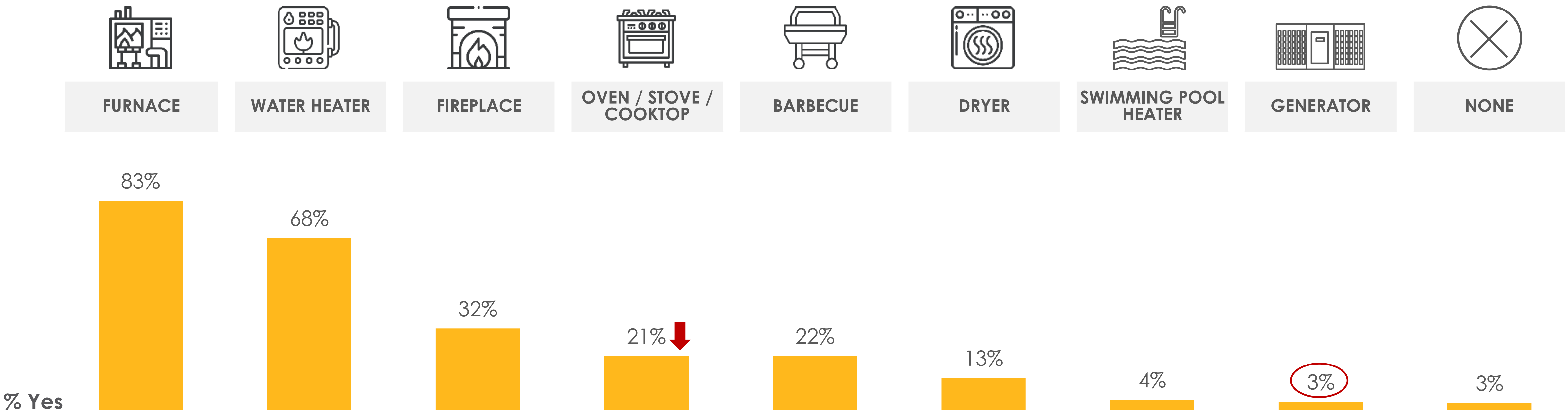
Most notably, a majority (54%; +12 pts vs. 2021) and statistically higher proportion relative to previous waves say they would get a line locate before digging. This marks the first iteration of the Safety & Compliance survey in which a majority has acknowledged the importance of getting a line locate before digging. What's more, majorities think their furnace is supposed to be inspected at least once a year (56%) and correctly liken the scent of natural gas to a distinctive rotten egg/Sulphur/mercaptan smell (53%). Half (49%) have had a furnace inspection within the past year, with most (68%) having done this within the past two years. And seven in ten (70%) report having carbon monoxide alarms next to all sleeping areas in their home.

Safety information recall across most metrics more or less remains on par with 2021, which saw a general decline relative to 2020. Among those who do recall receiving safety information from Enbridge Gas Inc., the Enbridge Gas bill (43%) remains the top source of awareness, followed at a distance by television (31%), emails from Enbridge (21%), the Enbridge Gas website (20%), and the Enbridge Gas safety email.

HEATING EQUIPMENT & MAINTENANCE

Natural Gas Equipment

- The proportion of natural gas users who report having most types of natural gas equipment or appliances is more or less on par with previous years, though fewer report having an oven/stove/cooktop (21%; -4 pts vs. 2021), relative to the previous year.
- Natural gas users living in the Windsor/Chatham region are more likely (at 49%), compared to those living in all other regions (20%) to report having a natural gas barbecue (with a natural gas line). Younger natural gas users (18-34) are more likely to have a natural gas range/over/stove/cooktop (41% vs. 20% aged 35+) but are less likely to have natural gas furnace (56% vs. 85%). Older natural gas users (75+) are among the most likely to have a natural gas fireplace (44% vs. 30% aged 74 or younger). Paper bill users are more likely to have a gas furnace (87% vs. 81% of eBill users). Those living in the legacy Union Gas territory are more likely to report having a natura gas dryer (15% vs. 11% of legacy EGD) and water heater (73% vs. 65%).



	Furnace	Water Heater	Fireplace	Oven / Stove / Cooktop	Barbecue	Dryer	Swimming Pool Heater	Generator	None
2021	85%	72%	33%	25%	21%	13%	5%	2%	3%
2020	85%	71%	35%	23%	21%	13%	5%	2%	2%
2019	85%	70%	33%	24%	20%	13%	4%	1%	4%

Q1. Which of the following appliances do you use inside or outside your home / unit? Select all that apply.
Base: All respondents; 2022 (n=1200); 2021 (n=1200); 2020 (n=1200); 2019 (n=1200)

Maintenance Responsibility

- Consistent with previous years, the highest proportion of natural gas users indicate that they are personally responsible for the maintenance across all types of natural gas equipment. Despite this, however, fewer indicate that they are responsible for the maintenance of their natural gas range/oven/stove/cooktop (66%; -12 pts vs. 2020) and fewer say they are responsible for the maintenance of a natural gas dryer (56%; -13 pts vs. 2020), relative to previous years.
- Natural gas users living in the legacy Enbridge Gas territory are more likely to report being personally responsible for maintenance of their furnace (63% vs. 56% of legacy Union Gas Distribution) and natural gas water heater (58% vs. 48%). eBill users are more likely to say they are responsible for the maintenance of their range/oven/stove/cooktop (71% vs. 54% of paper bill users) and natural gas furnace (63% vs. 56%).

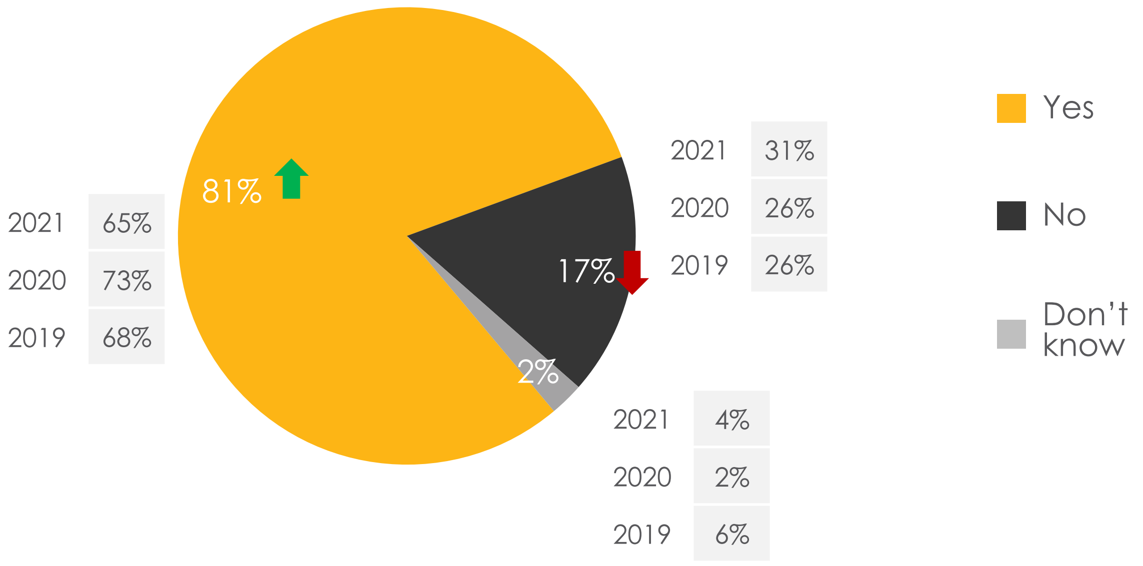
					MAINTENANCE RESPONSIBILITY																				
					You				Another person in your household				Landlord				Property manager				Don't know			
	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022
Natural gas furnace	(n=1015)	(n=1015)	(n=992)	(n=980)	60%	62%	60%	60%	13%	16%	17%	17%	9%	7%	8%	7%	3%	2%	3%	3%	1%	1%	2%	2%
Natural gas water heater	(n=842)	(n=850)	(n=854)	(n=818)	55%	58%	54%	54%	14%	16%	15%	16%	8%	7%	8%	8%	2%	2%	3%	3%	2%	2%	3%	3%
Natural gas fireplace	(n=390)	(n=410)	(n=390)	(n=379)	74%	67%	64%	62%	15%	20%	22%	25%	2%	2%	3%	1%	1%	0%	0%	1%	2%	1%	1%	3%
Natural gas range/ oven/stove/cooktop	(n=288)	(n=285)	(n=309)	(n=278)	73%	78%	70%	66%	17%	14%	20%	21%	4%	4%	3%	8%	2%	-	2%	3%	2%	1%	2%	2%
Natural gas barbecue (with gas line)	(n=235)	(n=257)	(n=256)	(n=260)	75%	74%	71%	68%	20%	22%	25%	28%	1%	2%	1%	1%	2%	0%	1%	2%	2%	>0%	1%	1%
Natural gas dryer	(n=158)	(n=166)	(n=162)	(n=162)	64%	69%	63%	56%	22%	19%	21%	27%	8%	5%	5%	7%	1%	3%	3%	3%	1%	2%	4%	3%
Natural gas swimming pool heater	(n=46)	(n=56)	(n=59)	(n=52)	52%	56%	57%	69%	16%	25%	24%	23%	4%	1%	1%	-	7%	3%	7%	7%	5%	3%	4%	-
Natural gas generator	(n=18**)	(n=23**)	(n=28**)	(n=41)	41%	50%	50%	43%	26%	9%	23%	15%	-	7%	3%	8%	14%	15%	5%	23%	-	-	-	-

Q2aa. Who is responsible for the maintenance of the following?
Base: Natural gas furnace or fireplace users

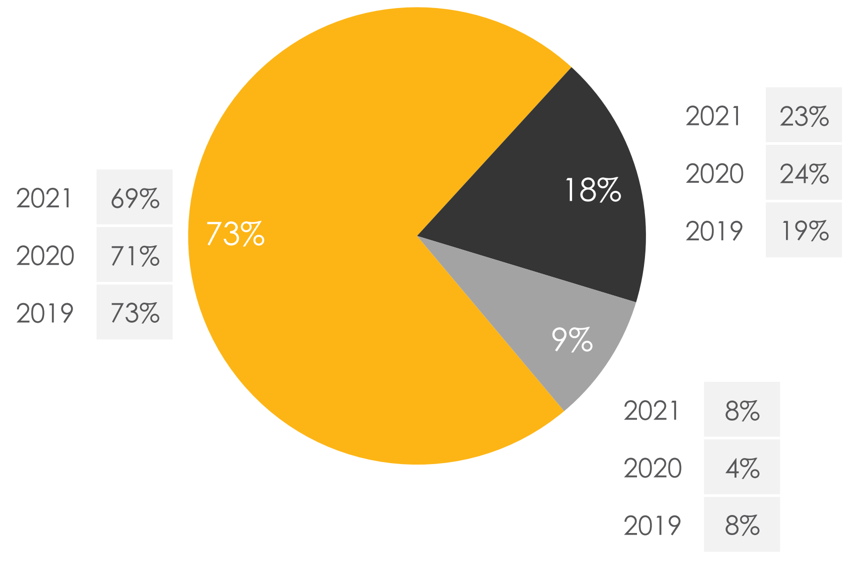
Multi-Unit Heating System Types

- Significantly higher proportion of natural gas users who reside in multi-unit dwellings indicate having centrally located heating (81%; +16 pts vs. 2021) in their building, relative to the previous year. On par with previous years, most natural gas users who reside in multi-unit dwellings have hot water heating systems (73%).

CENTRALLY LOCATED HEATING SYSTEM



CENTRALLY LOCATED HOT WATER HEATING SYSTEM



Q1a_1. Do you have any of the following in your building?
Base: Those who reside in an apartment/condo; Total 2022 (n=98); 2021 (n=95); 2020 (n=83); 2019 (n=114)

Natural Gas Furnace Maintenance

- Similar to what has been observed in previous years, nine in ten (91%) natural gas users clean or replace their furnace filter at least once a year, though fewer say they do this every month (6%; -3 pts vs. 2020) or at least four times a year (24%; -4 pts vs. 2021; -9 pts vs. 2020) and a significantly higher proportion (26%; +7 pts vs. 2021; +9 pts vs. 2020) admit doing this once a year.
- Younger natural gas users (18-34) are more likely to report cleaning or replacing their furnace filter less than once a year (11% vs. 3% aged 35+).

	2022	2021	2020	2019
Every month	6%	7%	9%	7%
At least four times a year	24%	28%	33%	34%
Two or three times per year	35%	36%	33%	33%
Once a year	26%	19%	17%	18%
Less than once a year	4%	5%	3%	2%
Never	2%	2%	3%	2%
Don't know	4%	3%	2%	3%

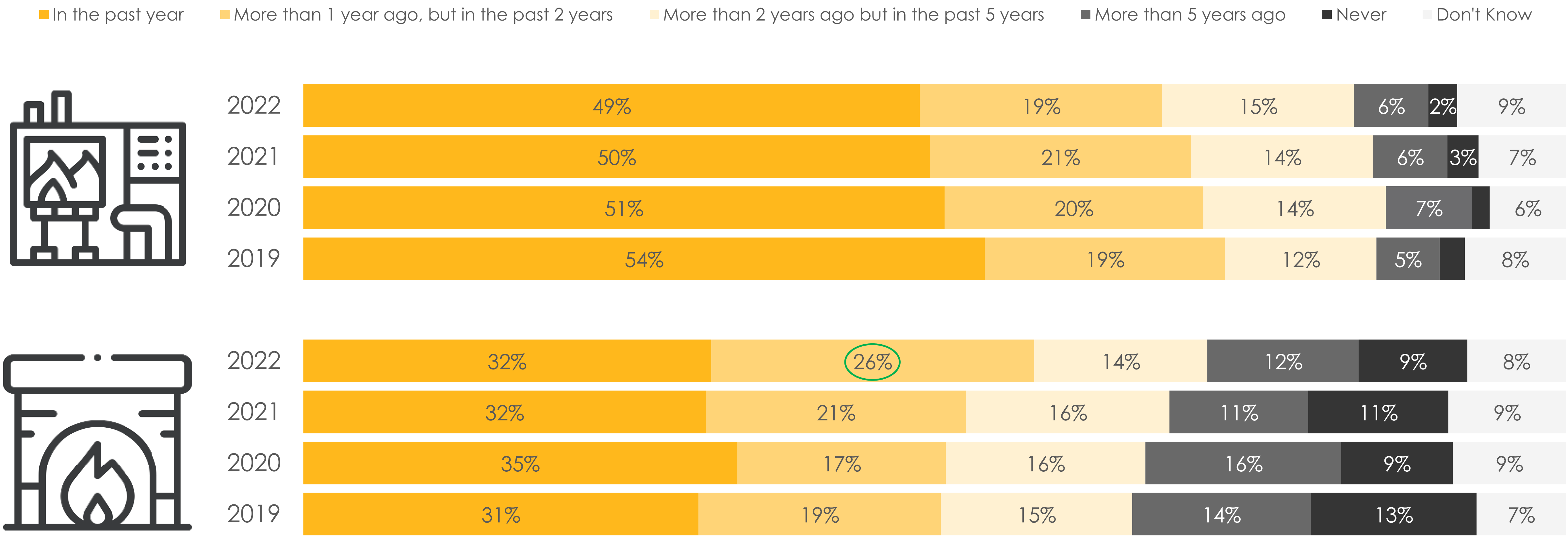
% At Least Once Per Year

2022	91%
2021	91%
2020	91%
2019	93%

Q2a. How frequently is your furnace filter cleaned or replaced?
Base: Respondents used a natural gas furnace in home or unit; Total 2022 (n=980); 2021 (n=992); 2020 (n=1015); 2019 (n=1015)

Furnace & Fireplace Inspection

- Half (49%) of natural gas users with a natural gas furnace had an inspection within the past year, though just one in three (32%) did this for their natural gas fireplace, figures which are consistent with previous years on both counts.
- The 65+ cohort of natural gas users is much more likely to report having their natural gas furnace inspected within the past year (57% vs. 43% under 65). Natural gas users living in Union Gas East region are more likely (at 69%), compared to those living in all other regions (49%) to have had their furnace inspected within the past year. Natural gas users living in the legacy Union Gas territory are more likely to have had their furnace inspected more than 2 years ago but within the past 5 years (20% vs. 12% legacy Enbridge Gas Distribution).

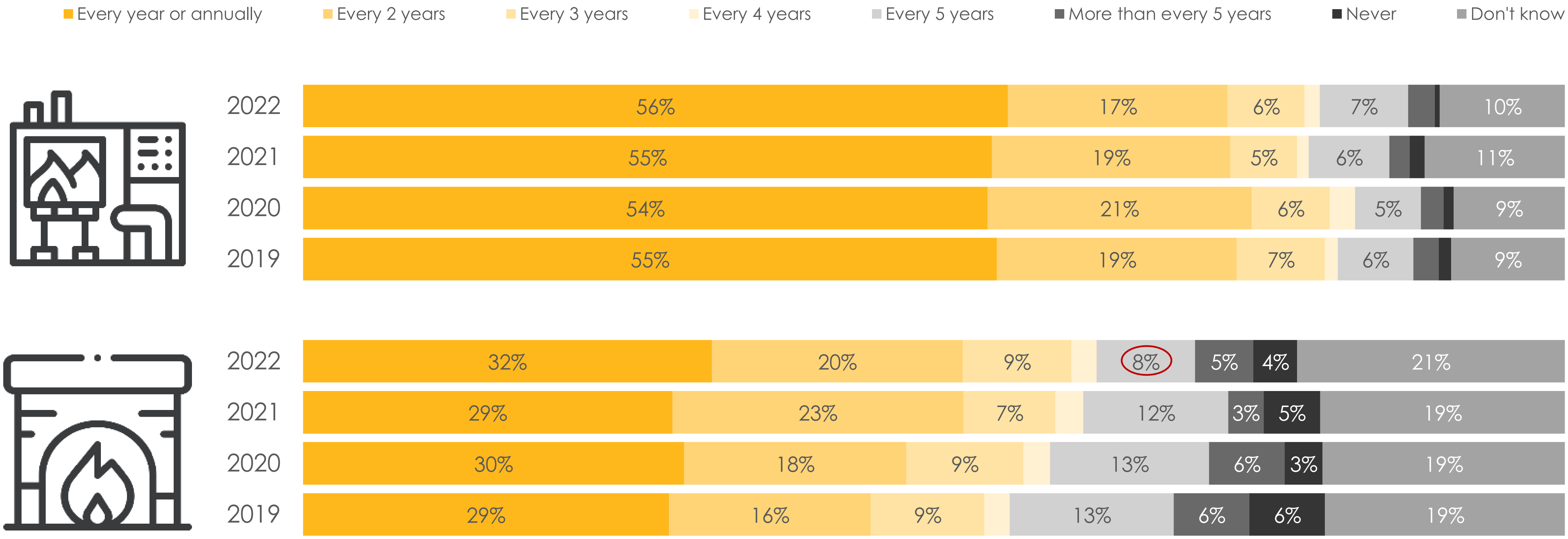


Note: Values less than 3% not labelled.

Q2b. When was the last time your natural gas fireplace/furnace was inspected by a certified technician? Was it…
Base: Have a natural gas furnace; Total 2022 (n=980); 2021 (n=992); 2020 (n=1015); 2019 (n=1015)
Have a natural gas fireplace; Total 2022 (n=379); 2021 (n=390); 2020 (n=410); 2019 (n=390)

When Inspection is Required

- A majority (56%) of natural gas users who have a natural gas furnace believe it should be inspected annually compared to just over three in ten (32%) of those who have a natural gas fireplace, figures which are on par with previous years, on both counts.
- Natural gas users living in the legacy Enbridge Gas Distribution are more likely to think furnaces need to be inspected on an annual basis (60% vs. 50% legacy Union Gas territory). Three-fifths (60%) of natural gas users aged 55+ think furnaces need to be inspected on an annual basis whereas less than half (47%) under the age of 55 believe the same.

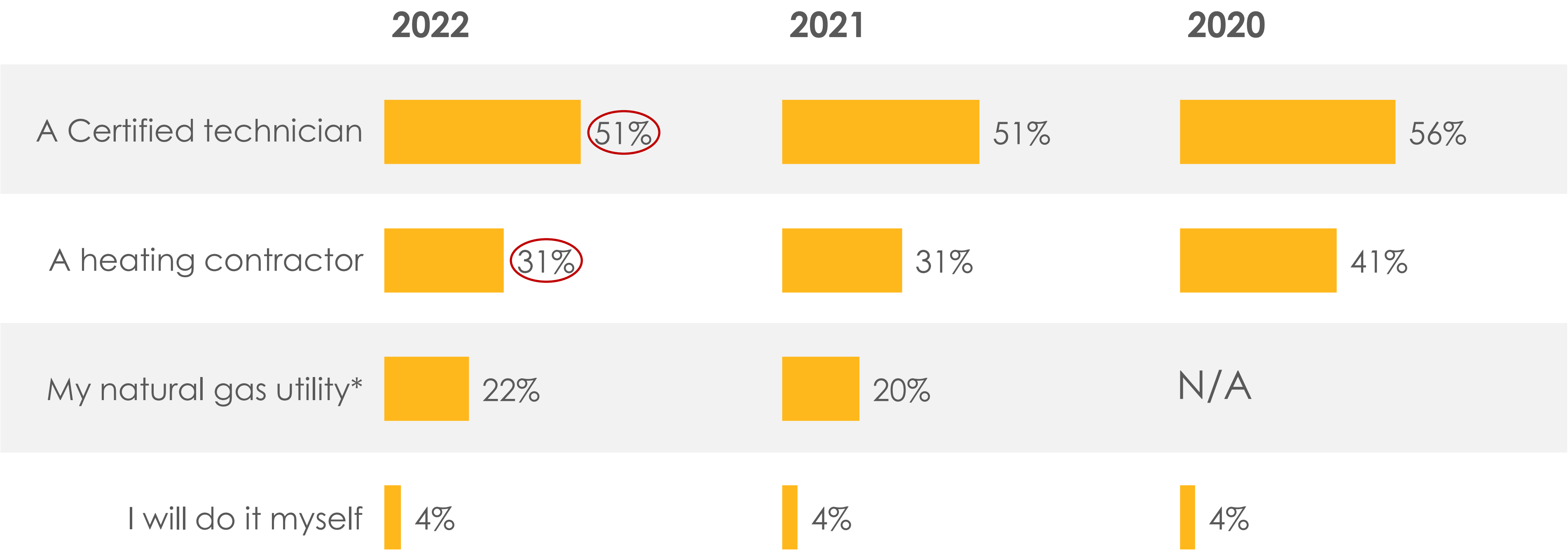


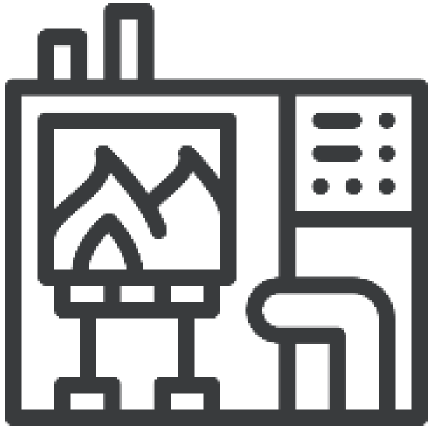
Note: Values less than 3% not labelled.

Q2aab. How often do you think that you need to have your natural gas furnace / fireplace inspected?
Base: Have a natural gas furnace; Total 2022 (n=980); 2021 (n=1014); 2020 (n=1015); 2019 (n=1015)
Have a natural gas fireplace; Total 2022 (n=379); 2021 (n=390); 2020 (n=410); 2019 (n=390)

Natural Gas Furnace Inspection

- Similar to 2021, natural gas users most frequently cite a certified technician (51%) as the person they would contact to service or inspect their natural gas furnace, followed by a heating contractor (31%). Statistical significance is not noteworthy, given that a new response category was added in the 2021 survey.
- Natural gas users living in the legacy Enbridge Gas Distribution territory are more likely to say they would contact their natural gas utility (25% vs. 17% legacy Union Gas). Older natural gas users (75+) are more likely to indicate that they would contact a heating contractor (41% vs. 29% under 74) but are less likely to contact a certified technician (39% vs. 53%).



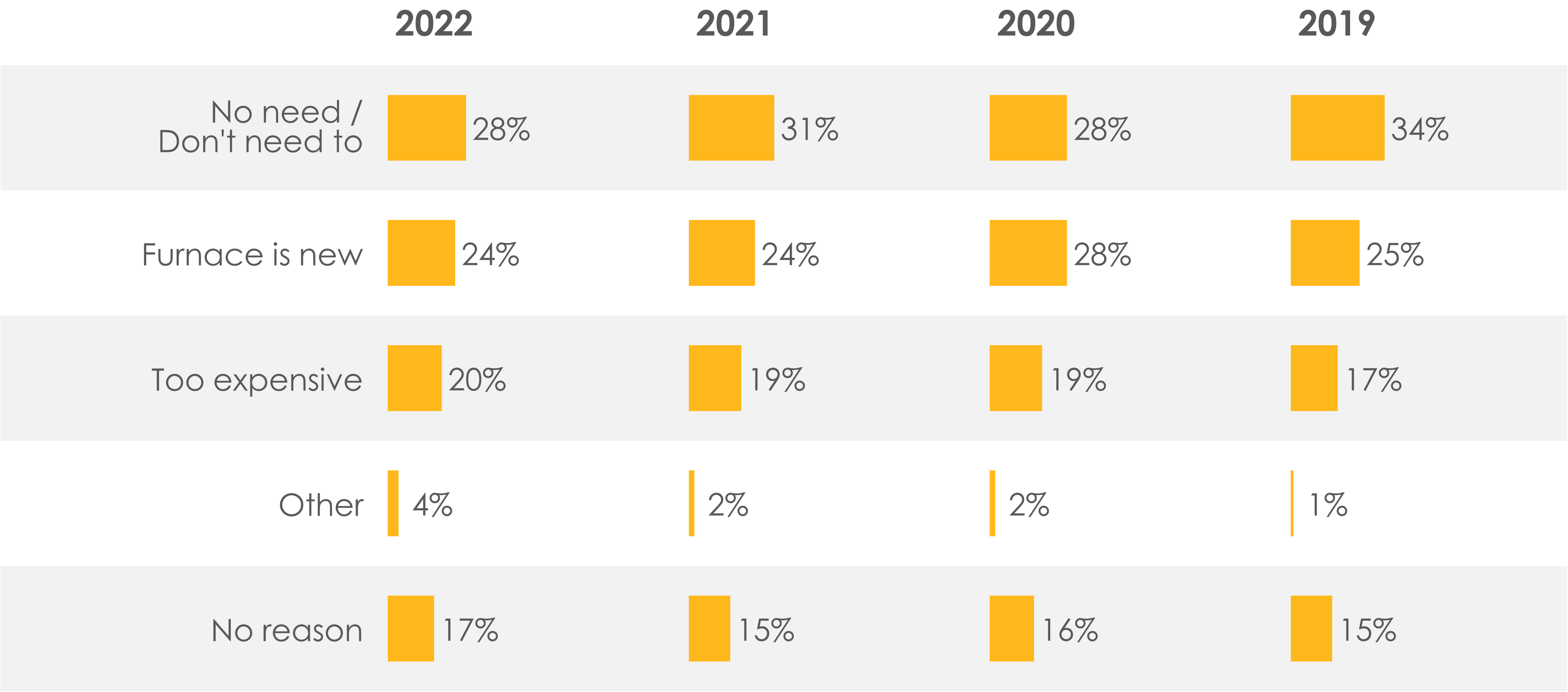


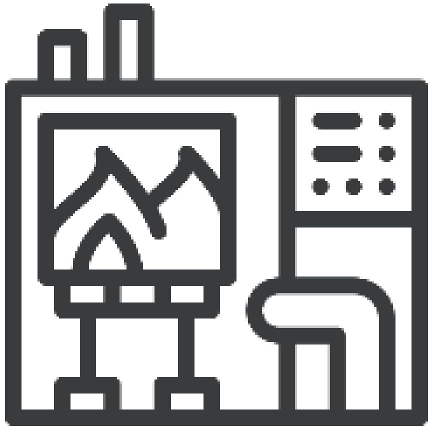
Note: Values less than 4% not shown

Mentions >3% not shown
*response option was added in 2021.
NEW Q2aab-2. Who would you contact to service or inspect your natural gas furnace?
Base: Have a natural gas furnace; Total 2022 (n=980); 2021 (n=992); 2020 (n=1015)

Reasons For No Furnace Maintenance

- A lack of necessity (28%), cost (20%) or having a new furnace (24%) are most commonly cited by those who have not had their furnace inspected in the past year as reasons for not doing this, figures which are on par with previous years.



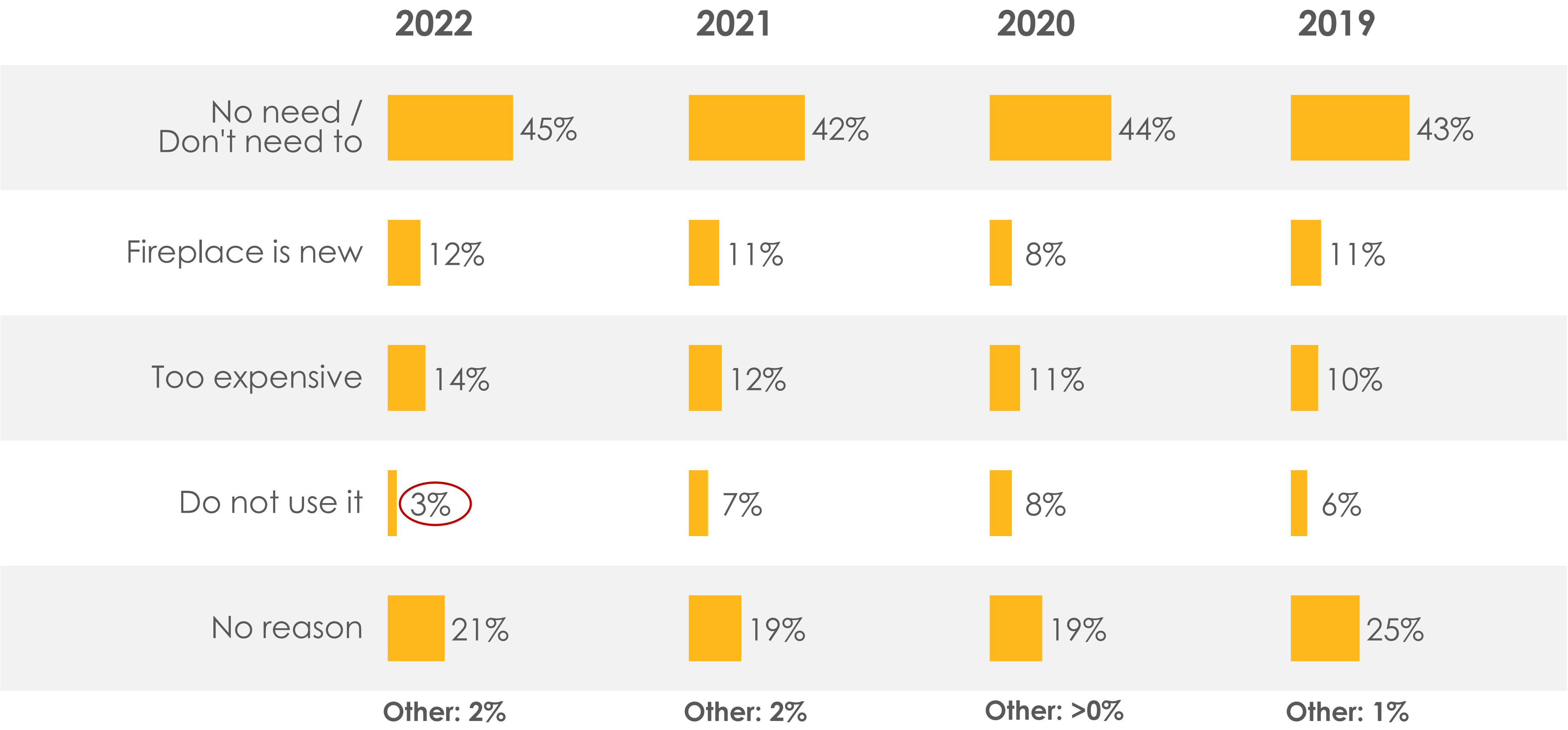


Note: Values less than 4% not shown

Q2c. Why have you not had your natural gas furnace or fireplace inspected on an annual basis]?
Base: Had their fireplace or furnace last inspected over a year ago; Total 2022 (n=430); 2021 (n=454); 2020 (n=452); 2019 (n=406)

Reasons For No Fireplace Maintenance

- Similar to furnaces, a lack of necessity (45%), cost (14%) or having a new furnace (12%) are most commonly cited by those who have not had their fireplace inspected in the past year as reasons for not doing this, figures which are on par with previous years.



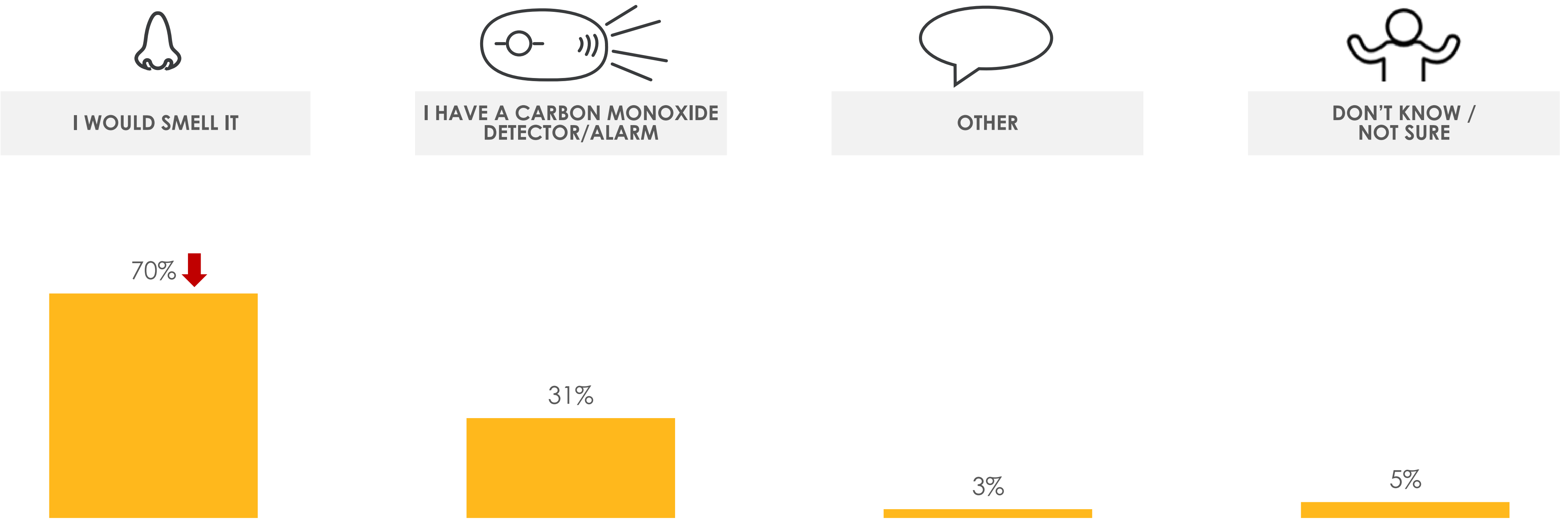
Note: Values less than 4% not shown

Q2c. Why have you not had your natural gas furnace or fireplace inspected on an annual basis]?
Base: Had their fireplace or furnace last inspected over a year ago; Total 2022 (n=229); 2021 (n=232); 2020 (n=240); 2019 (n=244)

NATURAL GAS SAFETY

Detecting A Natural Gas Leak

- Virtually all (95%) natural gas users are confident they would know how to detect a natural gas leak, a figure which is on par with previous years, with most indicating that the scent (70%) would give it away. Relative to 2021, fewer natural gas users indicate that they would detect a natural gas leak using scent (70%; -4 pts) while the proportion of natural gas users that say they would detect it using their carbon monoxide alarm (31%) more or less remain consistent.
- Natural gas users under the age of 34 are more likely to admit they aren't sure how to detect a natural gas leak (10% vs. 5% across all other age groups). Older natural gas users (65+) are among the most likely to say they would use scent, to detect a natural gas leak (77% vs. 66% across all other age groups). eBill users are more likely (at 34%) than paper bill users (27%) to say they would use their carbon monoxide alarm.



	I WOULD SMELL IT	I HAVE A CARBON MONOXIDE DETECTOR/ALARM	OTHER	DON'T KNOW / NOT SURE
2021	74%	28%	3%	5%
2020	72%	29%	3%	6%
2019	69%	33%	2%	6%

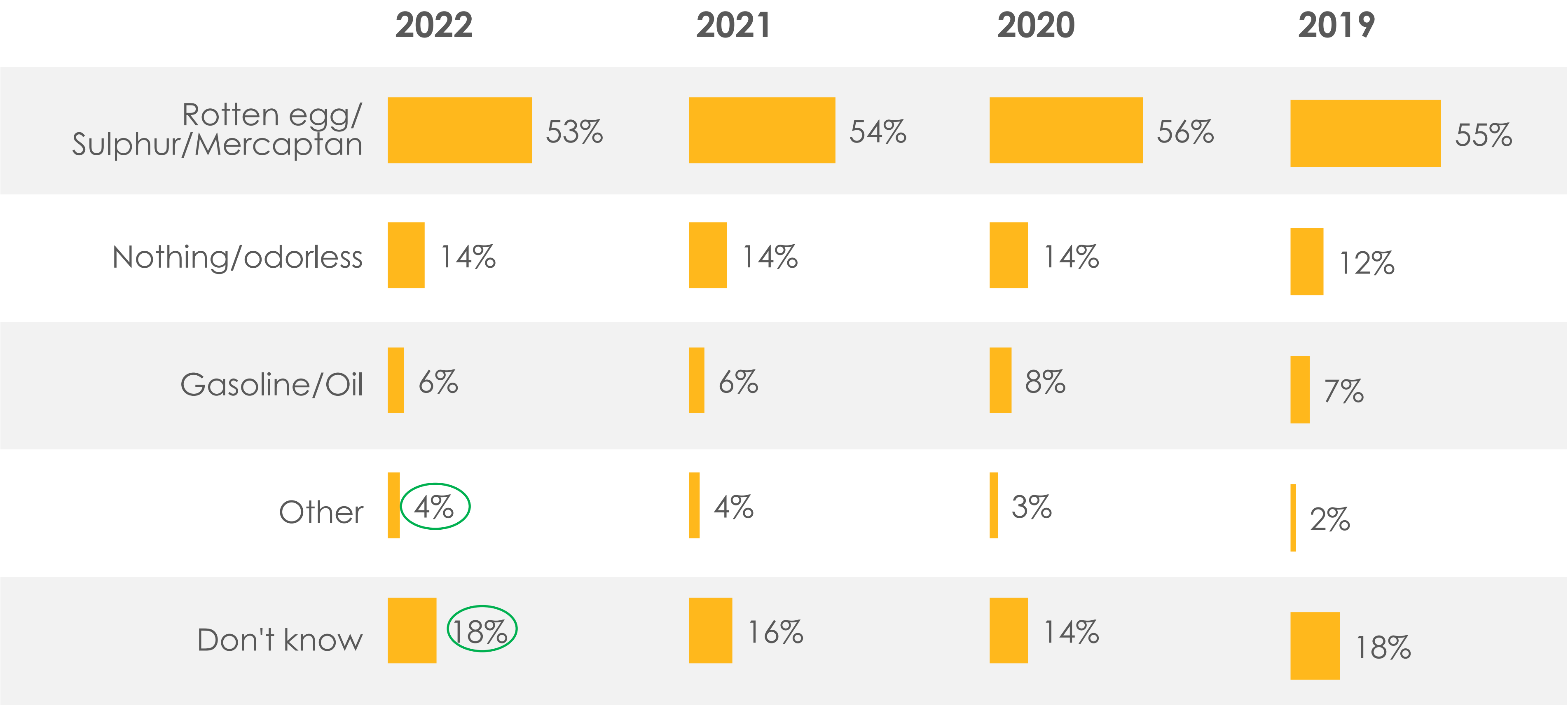
NONE:
2022: 0%
2021: 1%
2020: 1%
2019: 1%

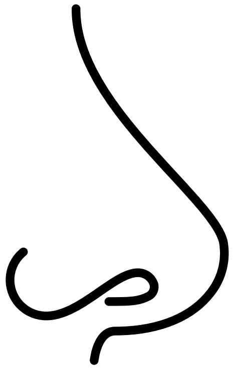
Q4a. How would you know you had a natural gas leak in your home / unit?
Base: All respondents; Total 2022 (n=1200); 2021 (n=1200); 2020 (n=1200); 2019 (n=1200)

Note: Values less than 4% not shown

Natural Gas Smell

- A majority (53%) of natural gas users think natural gas has a distinctive rotten egg/Sulphur/mercaptan smell, while fourteen percent (14%) say it is odorless, figures which are on par with previous years.
- Natural gas users aged 34 or younger are more likely to indicate that natural gas smells like gasoline/oil (15% vs. 5% 35 and older). This group is more likely to feel as though they aren't sure what natural gas smells like (29% vs. 17%).





Data less than 3% not shown
Q4a1. What does the natural gas you receive at your residence smell like?
Base: All respondents; Total 2022 (n=1200); 2021 (n=1200); 2020 (n=1200); 2019 (n=1200)

Note: Values less than 4% not shown

When A Gas Leak is Suspected

- When asked what they would do if they suspected a natural gas leak in their home, calling the gas company continues to top the list, though statistically lower proportions cite this action relative to the previous year (23%; -6 pts vs. 2021). More natural gas users say they would get out of the house and then call the fire department (15%; +6 pts vs. 2021). Fewer would call 911 (13%; -8 pts vs. 2021) or get out of the house (13%; -11 pts vs. 2021; -4 pts vs. 2020).
- Younger natural gas users (18-34) are among the most likely to indicate that they would call 911, if they were to suspect a natural gas leak (28% vs. 12% across all other age groups). eBill users are more likely (at 8%) than paper bill users (5%) to indicate that they would open windows/doors and/or call Union/Enbridge Gas or 911, if they were to suspect a natural gas leak. Natural gas users living in the legacy Union Gas Distribution territory are more likely to say they would call an inspector/technician (9% vs. 4% legacy Enbridge Gas).

2022		2021		2020		2019	
Will call Union Enbridge Gas / Gas Company	23% ↓	Will call Union Enbridge Gas / Gas Company	29%	Will call Union Enbridge Gas / Gas Company	18%	Will call gas company	23%
Will get out of the house and call 911 / Fire Department	15% ↑	Will get out of the house	24%	Will get out of the house	17%	Will get out of the house	12%
Will call 911/ fire department	13% ↓	Will call 911/ fire department	21%	Will get out of the house and call 911 / Fire Department	17%	Will get out of the house and call 911	16%
Will get out of the house	13% ↓	Will get out of the house and call Union Gas / Gas Company	10%	Will get out of the house and call Union Gas / Gas Company	14%	Will get out of the house and call gas company	15%
Will get out of the house and call Union Gas / Gas Company	12%	Will call an inspector/ technician	9%	Will call 911/ fire department	12%	Will call 911 / fire department	13%
Open windows/doors; and/or call Union/Enbridge Gas/Gas company/911	7%	Will get out of the house and call 911 / Fire Department	9%	Open windows/doors; and/or call Union/Enbridge Gas/Gas company/911	10%	Open windows/ doors	8%
Will call an inspector/ technician	6% ↓	Open windows/doors; and/or call Union/Enbridge Gas/Gas company/911	8%	Shut off gas valve	8%	Shut off gas valve	6%
Shut off gas valve	4%	Shut off gas valve	6%	Will call an inspector/ technician	8%	Will call an inspector / technician	6%
Will call the property manager/ security/ landlord	4%	Will call for help (unspecified)	5%	Will call for help (unspecified)	4%	Will call for help (unspecified)	3%

Data less than 5% not shown
Q4aa. What would you do if you suspected a natural gas leak in your home / unit?
Base: All respondents; Total 2022 (n=1200); 2021 (n=1200); 2020 (n=1200); 2019 (n=1200)

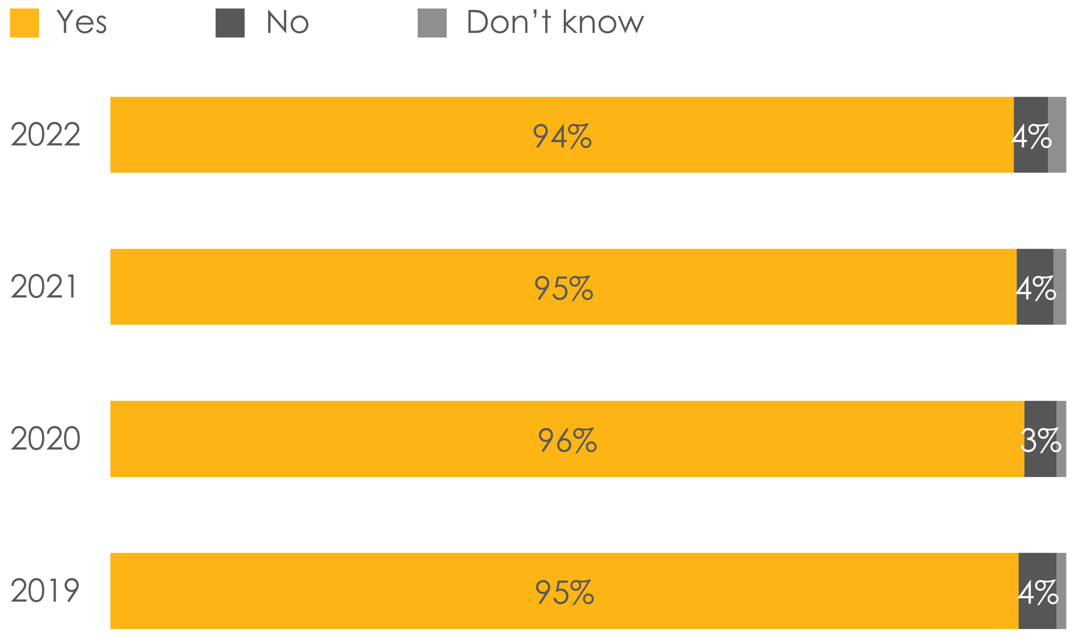
Note: Responses less than 5% not shown

CARBON MONOXIDE ALARMS AND SAFETY AWARENESS

Carbon Monoxide Alarm Usage

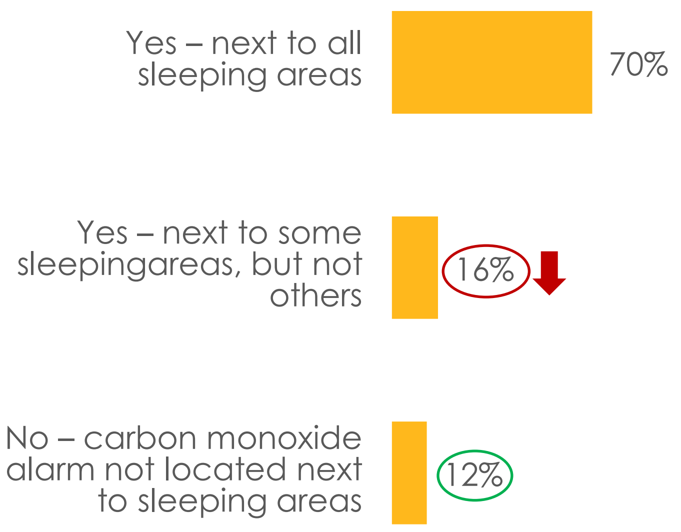
- Virtually all (94%) natural gas users have a working carbon monoxide alarm(s), of which seven in ten (70%) say they have alarms near all sleeping areas. Concerningly, more than one in ten (12%; +3 pts vs. 2020) of this group report having no carbon monoxide alarms located next to sleeping areas.
- Natural gas users living in the legacy Enbridge Gas Distribution territory are more likely to say they have carbon monoxide alarms next to all sleeping areas (73% vs. 67% legacy Union Gas). Younger natural gas users (18-34) are among the most likely to admit to not having a working carbon monoxide alarms installed (9% vs. 3% aged 35+).

CARBON MONOXIDE ALARM IN HOME



Note: Values less than 3% not labelled

ALARMS NEAR SLEEPING AREAS

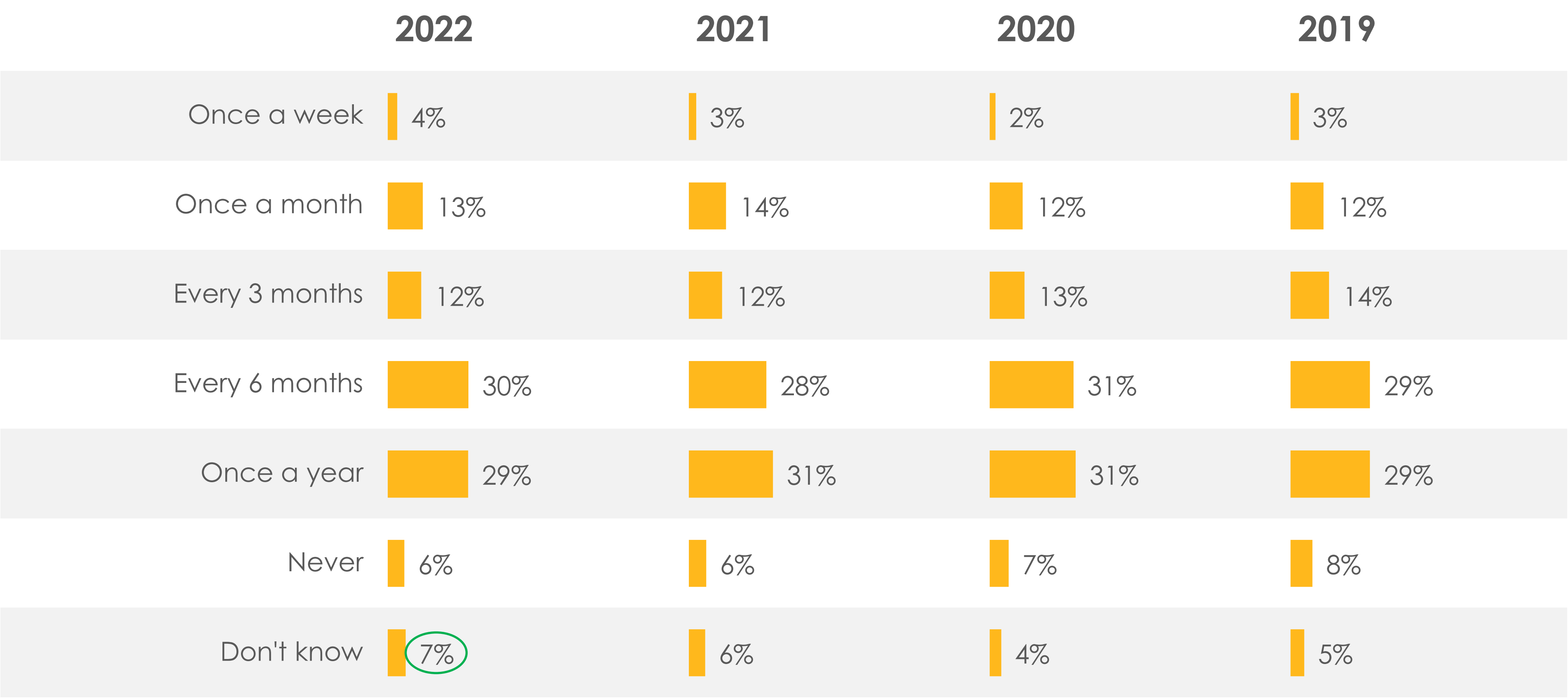


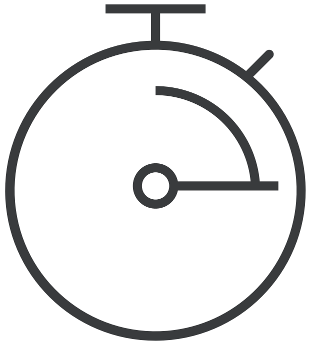
	2021	2020	2019
Yes – next to all sleeping areas	67%	70%	68%
Yes – next to some sleepingareas, but not others	20%	20%	20%
No – carbon monoxide alarm not located next to sleeping areas	13%	9%	12%

CO1: Do you have any working Carbon Monoxide Alarms, or CO Detectors, installed in your home / unit?
Base: All respondents; Total 2022 (n=1200); 2021 (n=1200); 2020 (n=1200); 2019 (n=1200)
CO1B. Do you have a working carbon monoxide alarm installed next to each sleeping area in your home / unit?
Base: Have carbon monoxide alarms; Total 2022 (n=1130); 2021 (n=1136); 2020 (n=1143); 2019 (n=1136)

Frequency Check Carbon Monoxide Alarm

- Most natural gas users check their CO alarm once a year (29%) or every six months (30%). However, more than one in ten (13%) natural gas users with a CO alarm do not (6%) or are unsure (7%; +3 pts vs. 2020) how often they check it. Just four percent (4%) say they do this at least weekly.
- The cohort aged 35-44 are also among the most likely to admit they aren't sure how often they check their CO alarm (13% vs. 5% aged 45+).

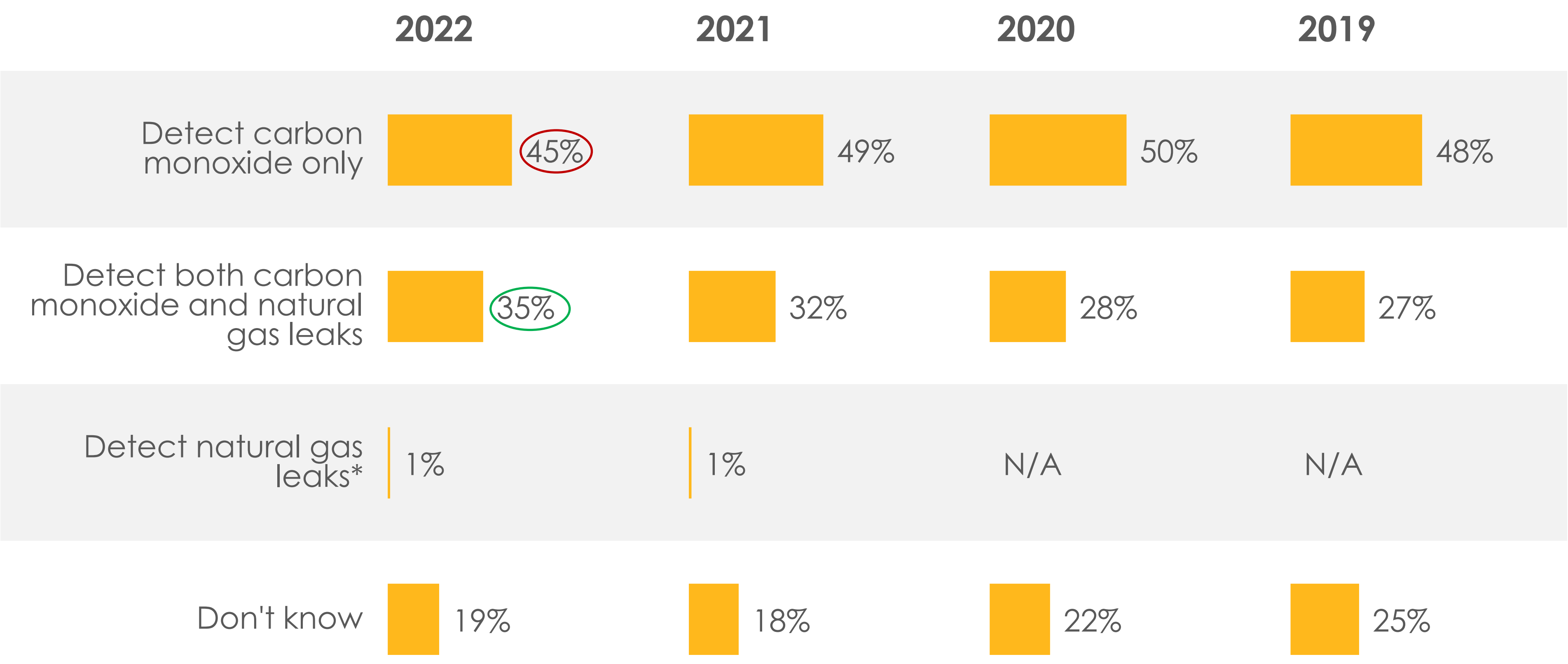


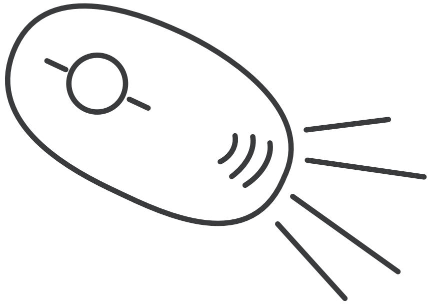


CO4: How often do you check your carbon monoxide alarm(s), to ensure it is operating?
Base: Have a carbon monoxide alarm; Total 2022 (n=1130); 2021 (n=1136); 2020 (n=1143); 2019 (n=1136)

Carbon Monoxide Alarm Knowledge

- More than two-thirds (45%; -5 pts vs. 2020) of natural gas users think their carbon monoxide alarm can detect carbon monoxide only, though fewer compared to 2020. Over one in three (35%; +7 pts vs. 2020) believe their carbon monoxide alarms are also capable of detecting natural gas leaks, a statistically higher proportion relative to 2020. Natural gas users that feel as though they don't know enough to offer an opinion on the matter (19%) remain more or less consistent. Just one percent (1%) think their carbon monoxide alarm can detect natural gas leaks.
- The cohort aged 65-74 are among the most likely to say they think their CO alarm can detect carbon monoxide only (56% vs. 42% across all other age groups).



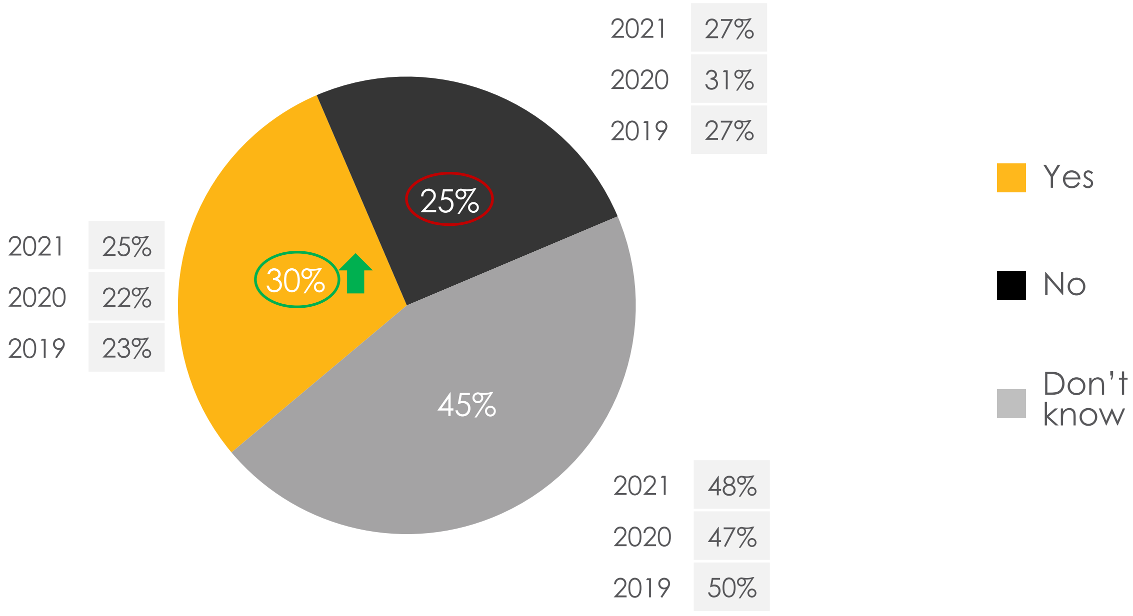


CO1B_bis: To the best of your knowledge, does your Carbon Monoxide alarm …?
Base: Have a carbon monoxide alarm; Total 2022 (n=1130); 2021 (n=1136); 2020 (n=1143); 2019 (n=1136)
*New response category in 2021.

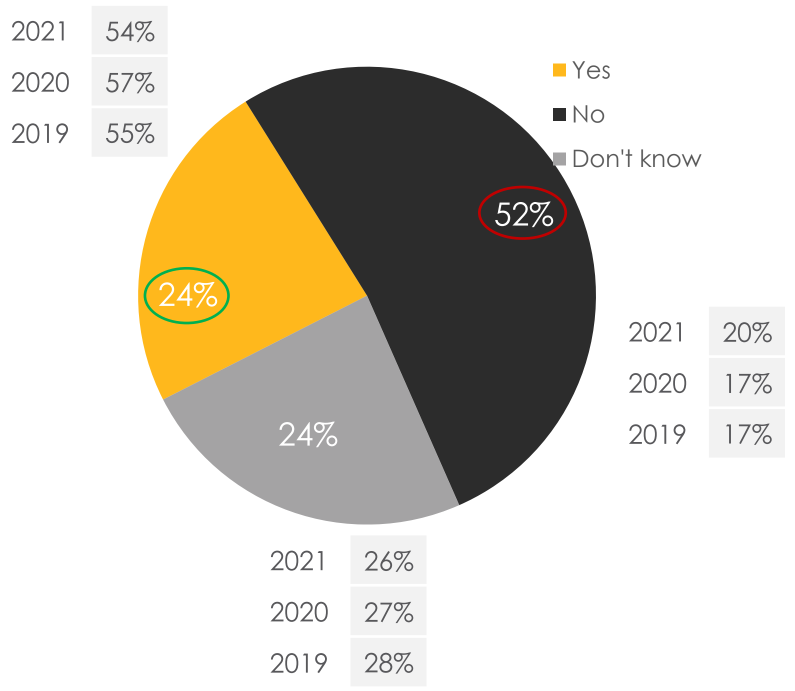
Natural Gas & Carbon Monoxide Alarm

- Year-over-year, a statistically higher proportion (30%; +5 pts) erroneously believe that a carbon monoxide alarm can also detect the presence of natural gas. Majorities (52%) admit that they do not have any natural gas detecting alarm devices.
- The 65-74 cohort is among the least likely to think carbon monoxide alarms can detect natural gas (21% vs. 34% under 64). eBill users are more likely to be of the opinion that carbon monoxide alarms can detect natural gas (32% vs. 26% of paper bill users). Natural gas users aged 45+ are more likely to admit they do not have any natural gas detecting alarms (55% vs. 40% under 45).

CARBON MONOXIDE ALARM CAN DETECT NATURAL GAS



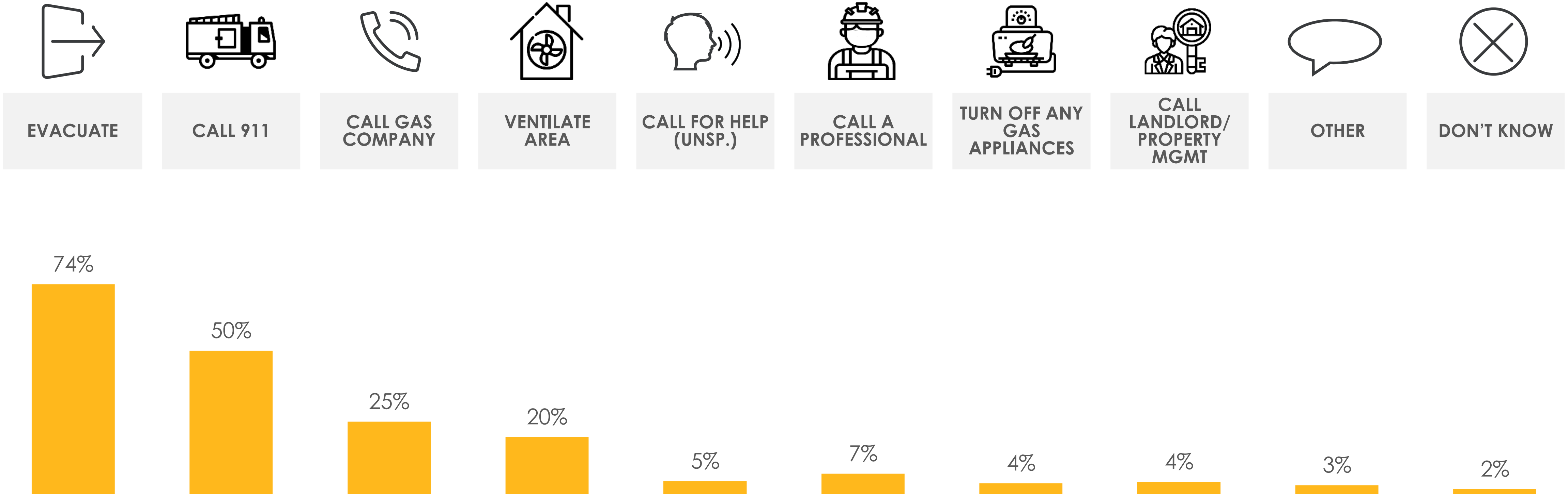
HAVE NATURAL GAS DETECTING ALARM DEVICES



CO5: To the best of your knowledge, does a carbon monoxide alarm, also detect the presence of natural gas in your home / unit?
CO6. Do you have any natural gas detecting alarm devices in your ...?
Base: All respondents; Total 2022 (n=1200); 2021 (n=1200); 2020 (n=1200); 2019 (n=1200)

Actions to Take if CO Detected (Unaided)

- If natural gas users were to suspect a carbon monoxide leak, three-quarters (74%) would evacuate the area and half (50%) would call 911. Only about one in four would call their gas company (25%) or ventilate the area (20%).
- Natural gas users aged 45+ are more likely to say they would evacuate the area, if they were to suspect a carbon monoxide leak (76% vs. 62% under 45). Natural gas users living in the legacy Enbridge Gas Distribution territory are more likely to say they would call their gas company (28% vs. 22% legacy Union Gas).



	Evacuate	Call 911	Call Gas Company	Ventilate Area	Call for Help (Unsp.)	Call a Professional	Turn off any Gas Appliances	Call Landlord/ Property Mgmt	Other	Don't Know
2021	72%	50%	25%	21%	6%	7%	4%	4%	3%	2%
2020	75%	50%	24%	21%	5%	7%	4%	4%	4%	2%
2019	74%	52%	25%	22%	5%	5%	5%	4%	2%	2%

Q5ccc. What should you do if you suspect a carbon monoxide leak in your home / unit?
Legacy wording: Q5ccc. What actions should you take when carbon monoxide is detected in your home?
Base: All respondents; Total 2022 (n=1200); 2021 (n=1200); 2020 (n=1200); 2019 (n=1200)

Note: Values less than 4% not shown

CROSS BORE AWARENESS

Actions Taken Before Digging

- Significantly higher proportions (54%; +12 pts vs. 2021; +13 pts vs. 2020) relative to previous years say they would get a line to locate before digging. Fewer (3%; -18 pts vs. 2020) claim that they would be looking for the pipeline location, relative to 2020.
- Natural gas users under 45 are less likely to call their gas company (23% vs. 45% aged 45+). However, the under 65 demographic is more likely to call the City (15% vs. 5% aged 65+). Natural gas users living in the legacy Union Gas territory are more likely to say they would get a line locate before digging (58% vs. 51% legacy Enbridge Gas Distribution).

2022	
Get a line to locate before digging (by calling Ontario one call or by going online)	54%
Call Enbridge/ Union gas/ utility company	41%
Call the City/ 311	11%
Call someone (unspecified)	4%
Look for the pipe line location	3%
Call an inspector/ contractor/ specialist	3%
Other	3%
Nothing	1%
Don't know	2%

2021	
Get a line to locate before digging (by calling Ontario one call or by going online)	42%
Call Enbridge/ Union gas/ utility company	40%
Call the City/ 311	9%
Call someone (unspecified)	4%
Look for the pipe line location	3%
Call an inspector/ contractor/ specialist	3%
Don't know	3%
Nothing	1%
Other	0%

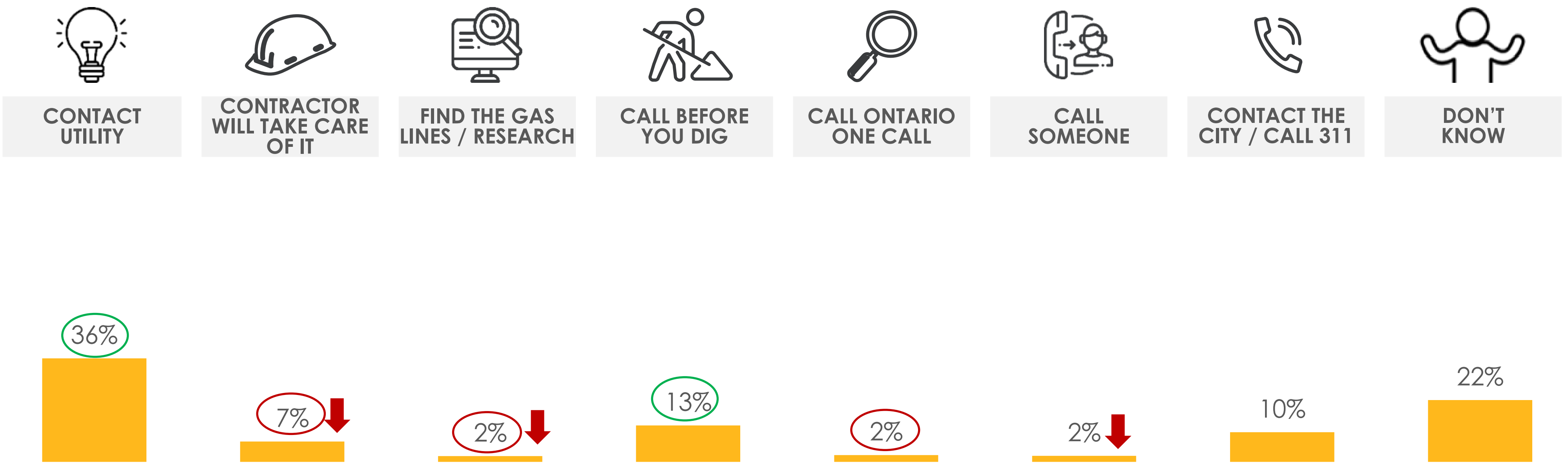
2020	
Call Enbridge/ Union gas/ utility company	41%
Get a line to locate before digging (by calling Ontario one call or by going online)	34%
Look for the pipe line location	21%
Call the City/ 311	10%
Call someone (unspecified)	6%
Other	4%
Don't know	3%
Nothing	1%

2019	
Call Enbridge/Union gas/utility company	42%
Get a line locate done before digging	38%
Call the city/311	8%
Call someone (unspecified)	3%
Look for the pipe line location	2%
Other	2%
Don't know	2%
Nothing	1%

Data less than 5% not shown Note: Values less than 3% not shown
Q5. On a different topic, suppose you needed to dig on your property - this could be tree planting, fence building, hammering in a stake, deck building, waterproofing a basement, etc. What would you do before digging on your property to prevent damaging a natural gas line? Note: adjustments were made to question wording in 2021.
Base: Live in a single family home; Total 2022 (n=1102); 2021 (n=1105); 2020 (n=1117); 2019 (n=1086)

Cross Bore Actions Taken

- Relative to previous years, more natural gas users say they would contact their utility (36%; +6 pts vs. 2020) whereas fewer would ask their contractor to take care of it (7%; -3 pts vs. 2021; -13 pts vs. 2020), if they needed to clear a blockage of a sewer beyond the walls of their house. Year-over-year, more would call before digging (13%; +8 pts vs. 2020) but fewer would do research to find the gas lines (2%; -4 pts vs. 2021; -7 pts vs. 2020).
- Natural gas users under the age of 55 are more likely to admit they are not sure what they would do, if they needed to clear a sewer blockage (29% vs. 18% aged 55+) and are less likely to call their gas company (23% vs. 43%).



	Contact Utility	Contractor Will Take Care of It	Find the Gas Lines / Research	Call Before You Dig	Call Ontario One Call	Call Someone	Contact the City / Call 311	Don't Know
2021	35%	10%	6%	11%	3%	4%	10%	20%
2020	30%	20%	9%	5%	4%	2%	8%	20%
2019	25%	20%	3%	11%	3%	3%	15%	13%

OTHER:
2022: 4%
2021: 1%
2020: 5%
2019: 1%

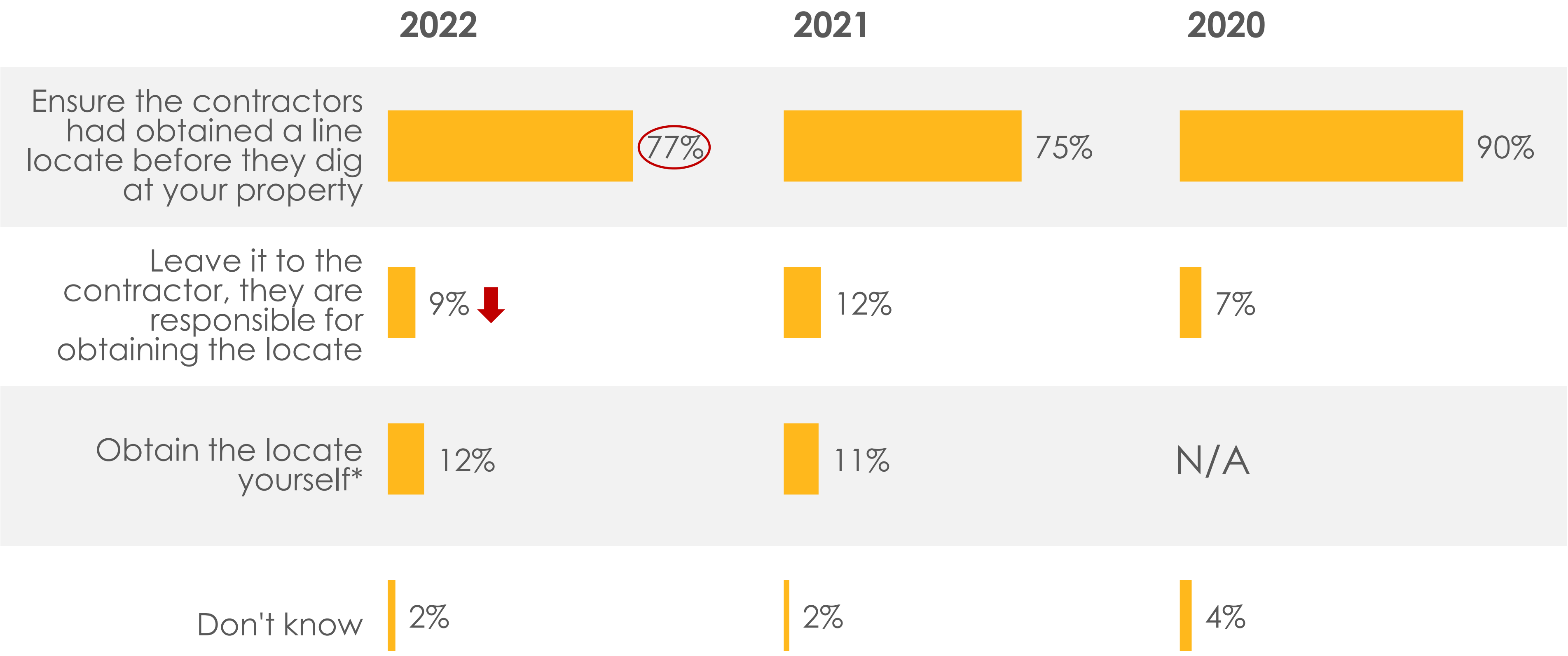
NONE:
2022: 3%
2021: 4%
2020: 1%
2019: 4%

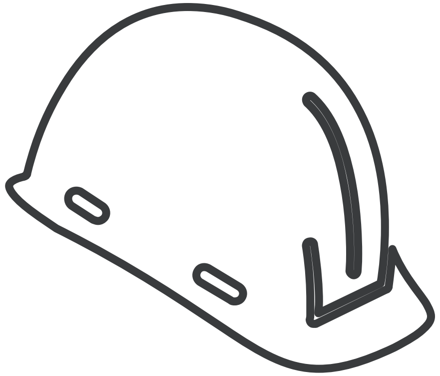
CBORE1: While rare, it's possible that a natural gas line is unintentionally installed through a sewer line. Suppose you need to clear a blockage of a sewer beyond the walls of your house/building by using a mechanical or high-pressure water jetting equipment, what would you do before you attempt to clear the blocked sewer or septic pipe outside the walls of your house or have it cleared by a contractor or a plumber to prevent damaging a natural gas line? [NEW 2020] *small update to question wording.
Base: Live in a single family home; Total 2022 (n=1102); 2021 (n=1105); 2020 (n=1117); 2019 (n=1086)

Note: Values less than 4% not shown

Digging on Property

- Not unlike 2021, most (77%) natural gas users who live in a single-family home say they would ensure the contractors had obtained a line locate before digging, if they needed to dig. The statistical significance is not noteworthy as a new response category was added in 2021.
- Among natural gas users who live in a single-family home, those aged 65+ are more likely to say they would ensure the contractors had obtained a line locate (85% vs. 72% under 65) before digging and are less likely to say they would leave this up to the contractors (5% vs. 12%).



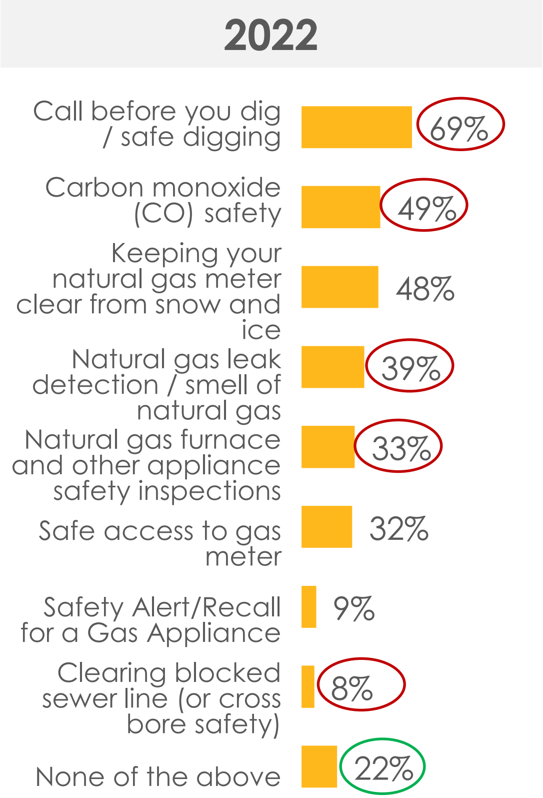


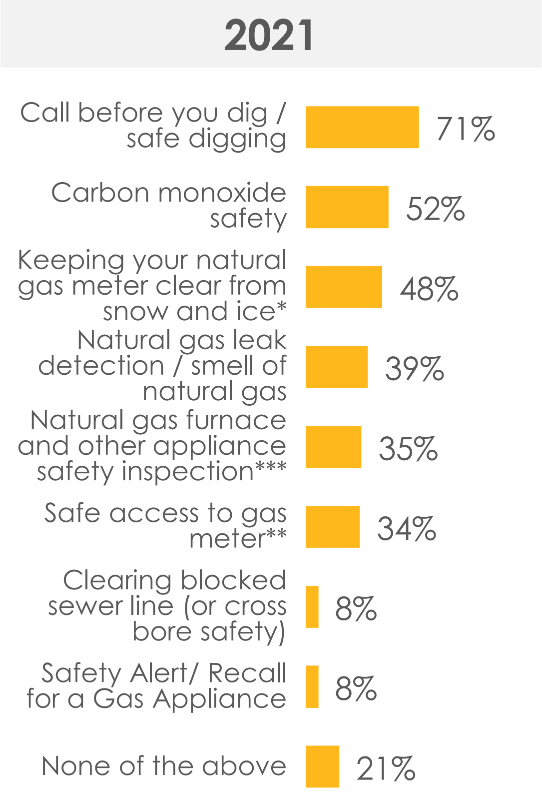
NEW Q5b. Once again, thinking of a contractor working on your property needed to dig for a variety of reasons including tree planting, fence building hammer in a stake, deck building, etc., would you…?
Base: Live in a single family home; Total 2022 (n=1102); 2021 (n=1105); 2020 (n=1200)
*New response category added in 2021.

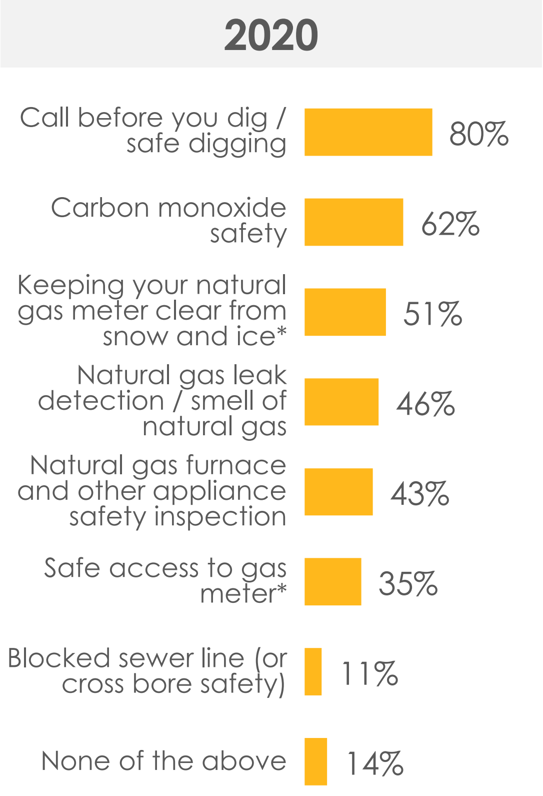
SAFETY COMMUNICATIONS

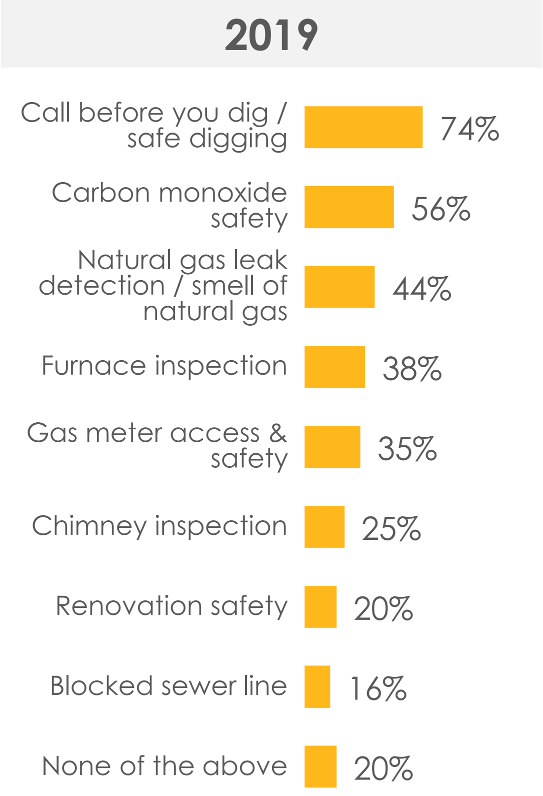
Safety Information Recall

- Safety information recall is down across most metrics, relative to previous years.
- Natural gas users living in legacy Union Gas territory and older natural gas users tend to be more likely to indicate recall of most safety topics. The 75+ cohort specifically is more likely to recall consuming information about safe access to gas meter (46% vs. 29% under 75) and natural gas furnace and other appliance safety inspections (50% vs. 30%).





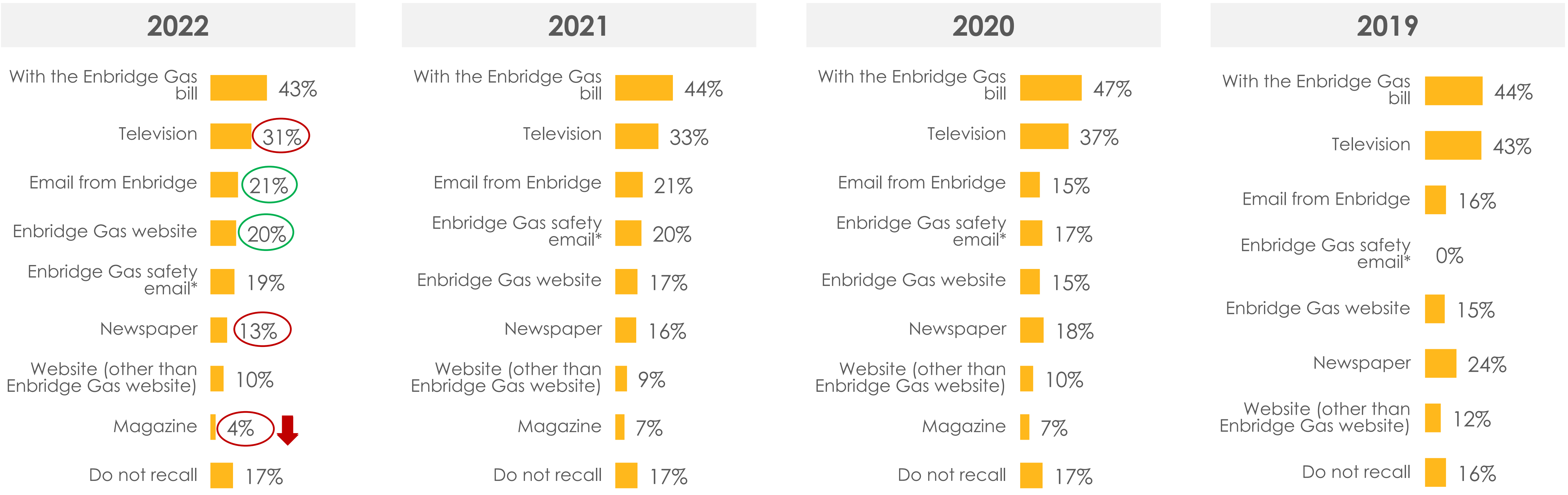




Q15a. Have you seen, heard or read any information before today about the following topics?
*New selection option in 2020; **Legacy wording: Gas meter access & safety *** Legacy wording: furnace inspection
Base: All respondents; Total 2022 (n=1200); 2021 (n=1200); 2020 (n=1200); 2019 (n=1200)

Source of Recall

- Television (31%; -6 pts vs. 2020), newspaper (13%; -5 pts vs. 2020) and magazine (4%; -3 pts vs. 2021; -3 pts vs. 2020) are cited by fewer as their sources of awareness, compared to the previous years.
- eBill users are more likely to cite the Enbridge Gas website (24% vs. 13% of paper bill natural gas users) or other website (12% vs.7%) as sources of recall. Older natural gas users (aged 75+) are more likely to mention newspaper (22% vs. 11% under 75), as their source of recall. Younger natural gas users (18-34) are among the most likely to cite Enbridge Gas Instagram page (13% vs. 2% 35+) as their source of awareness. Around half in the London & Sarnia (46%), Northeast (45%) and Northwest (49%) regions mention television, as their source of awareness compared to only three in ten (29%) natural gas users across all other regions. Natural gas users living in the legacy Enbridge Gas Distribution territory are more likely to list an email from Enbridge Gas, as their source of recall (24% vs. 18% legacy Union Gas) but less likely to mention television (27% vs. 38%).

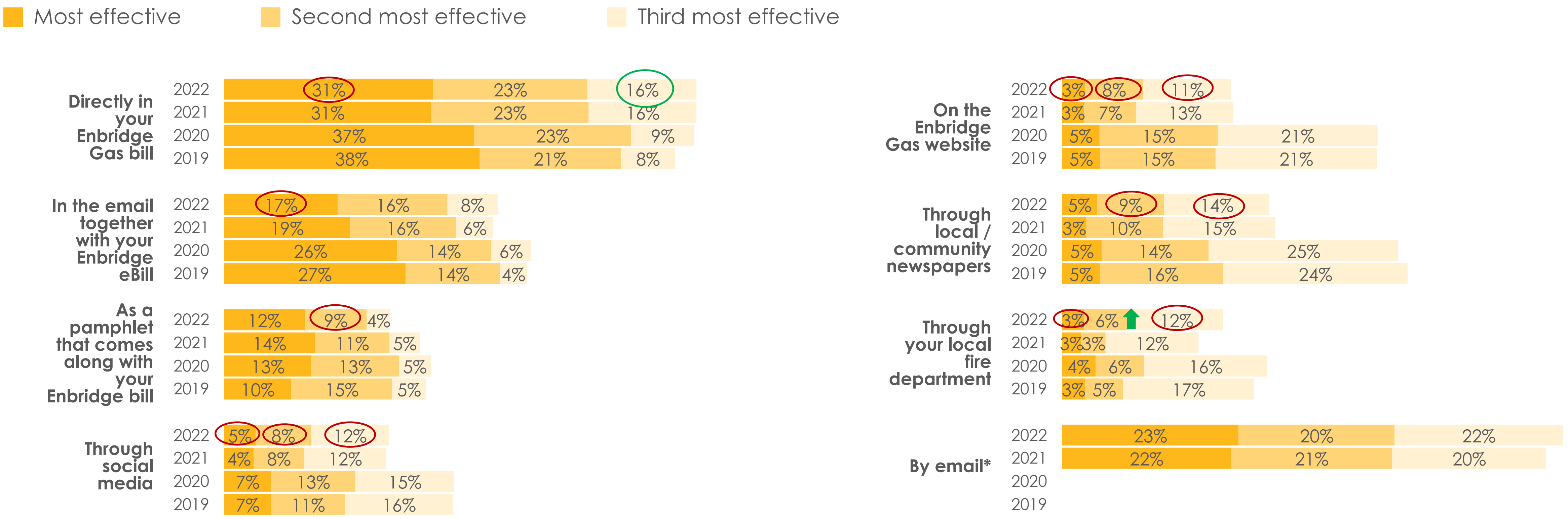


Q15b. Where do you remember seeing this information? Select all that apply.
*New selection option in 2020. Data less than 5% not shown
Base: Recall safety information; Total 2022 (n=935); 2021 (n=935); 2020 (n=1027); 2019 (n=953)

Note: Values less than 7% not shown

Safety News

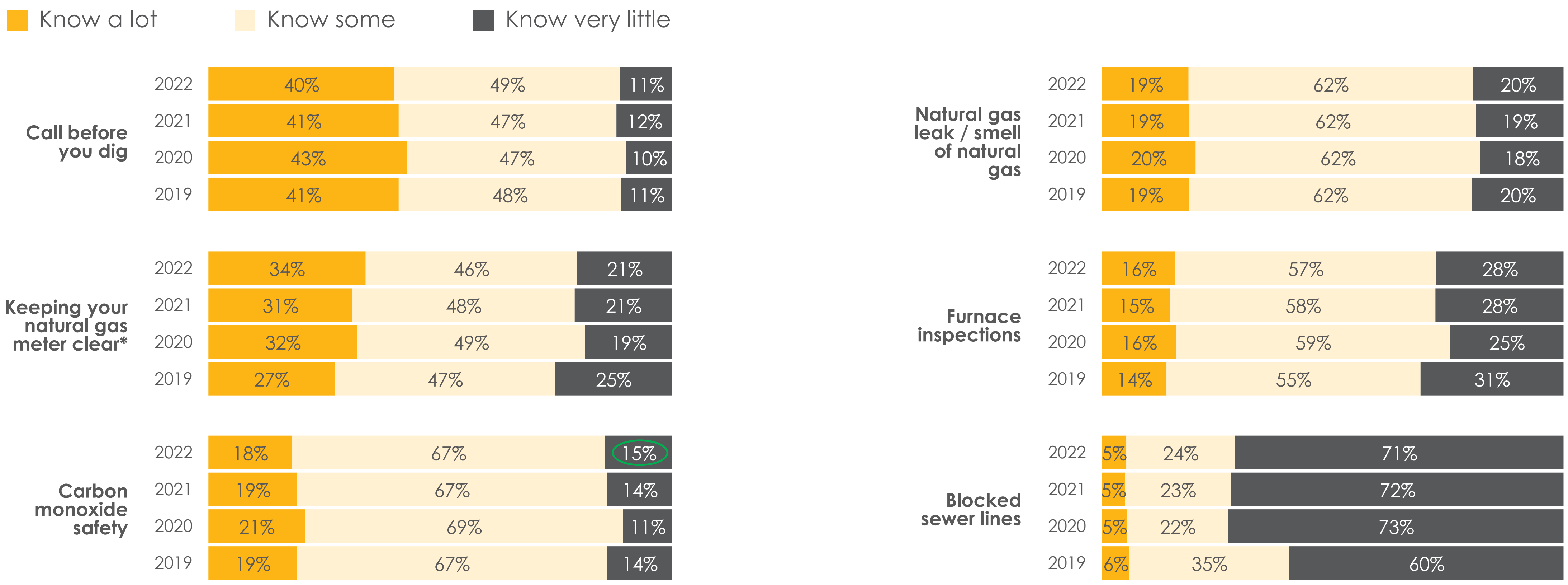
- Effectiveness scores are more or less on par with 2021, though remain down across most metrics, relative to the pre-2021 years.
- Natural gas users under the age of 55 are more likely to view social media (9% vs. 2% 55+) as being the most effective method of receiving safety news. Paper bill users are more likely to think having safety news directly in their Enbridge Gas bill would be most effective (38% vs. 28% of eBill users).



15bb. We would like to understand how Enbridge Gas can share safety news with you. Please select your top three choices.
Base: All respondents; Total 2022 (n=1200); 2021 (n=1200); 2020 (n=1200)
*New response category that was added in 2021.

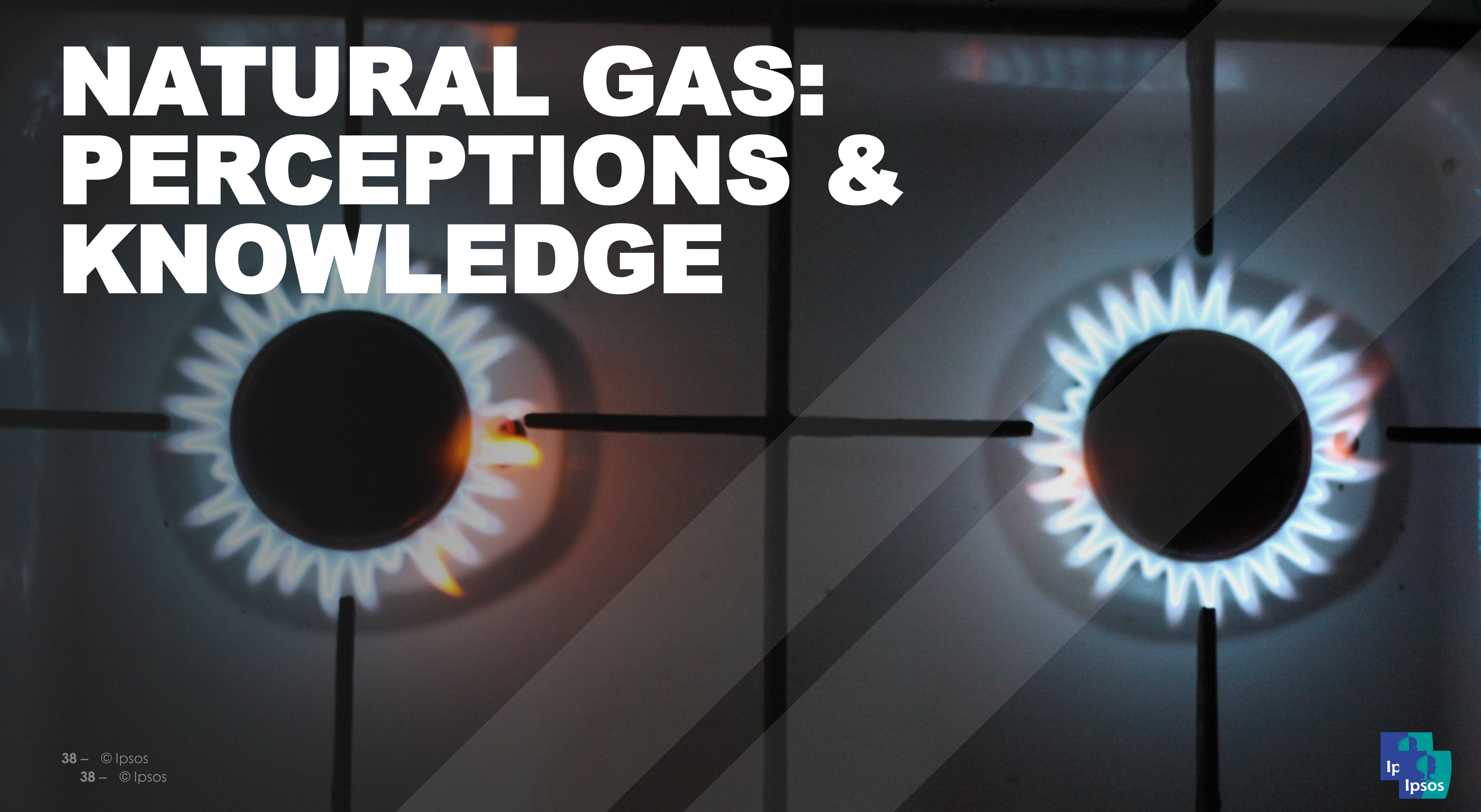
Safety Topics Knowledge

- Most natural gas users feel as though they are at least moderately knowledgeable about all safety topics, save for blocked sewer lines, at least according to their own self-assessed safety knowledge ratings.
- Safety topics knowledge tends to increase with age. Natural gas users living in the legacy Union Gas territory are more likely to indicate knowledge of keeping their natural gas meter clear (85% vs. 76% legacy Enbridge Gas Distribution). Nearly two thirds (65%) of Northwest region natural gas users claim to know a lot about keeping their natural gas meter clear making this only region in which a majority of natural gas users feels this is the case (33% across all other regions).



Q15c. How much would you say that you know about the following safety topics.
*Legacy wording: Gas meter access & safety.
Base: All respondents; Total 2022 (n=1200); 2021 (n=1200); 2020 (n=1200)

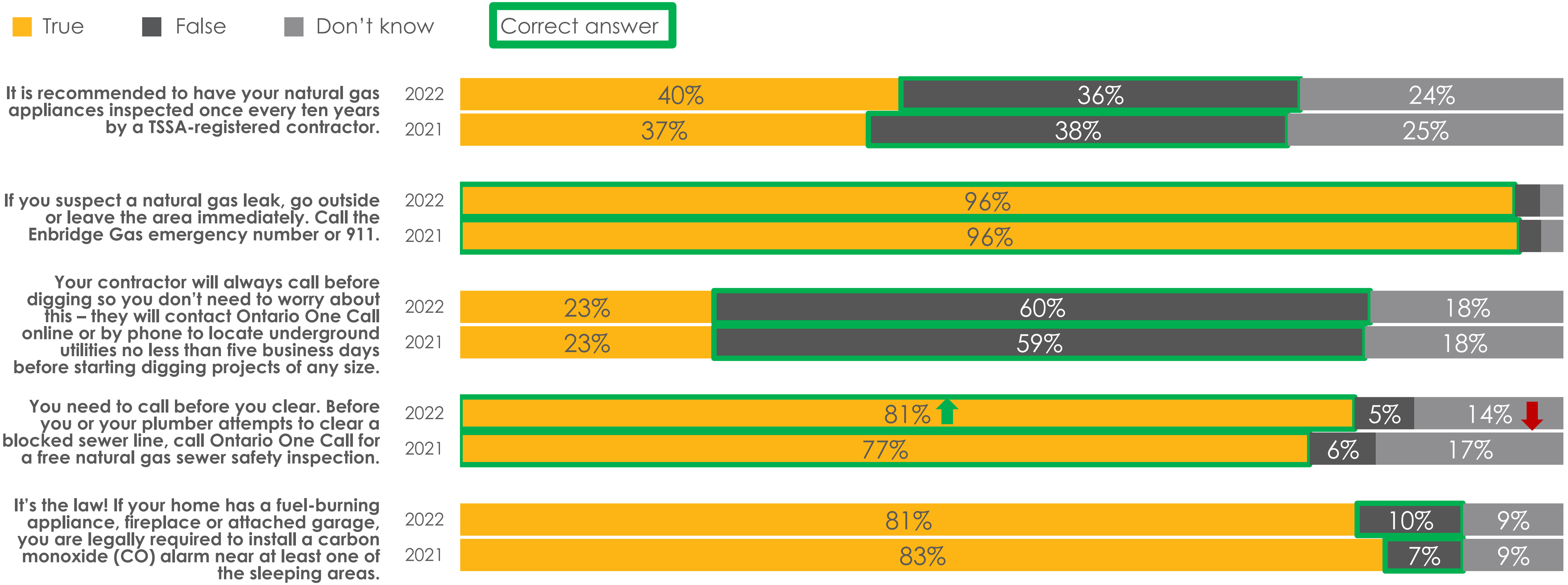
NATURAL GAS: PERCEPTIONS & KNOWLEDGE



38 – © Ipsos

Testing Natural Gas Safety Knowledge

- Natural gas safety knowledge is moderate to low. On the one hand, clear majorities know what to do when a natural gas leak is suspected (96%) or when clearing a blocked sewer line (81%; +4 pts vs. 2021). On the other hand, however, most do not know how often their natural gas appliances need to be inspected (36% correctly indicate the statement is false) or what the laws are, as they relate to carbon monoxide alarms (just 10% correctly indicate that the statement is false).
- The 75+ cohort is among the most likely to correctly indicate that it is not recommended to wait 10 years to inspect your furnace (45% vs. 35% under 75).

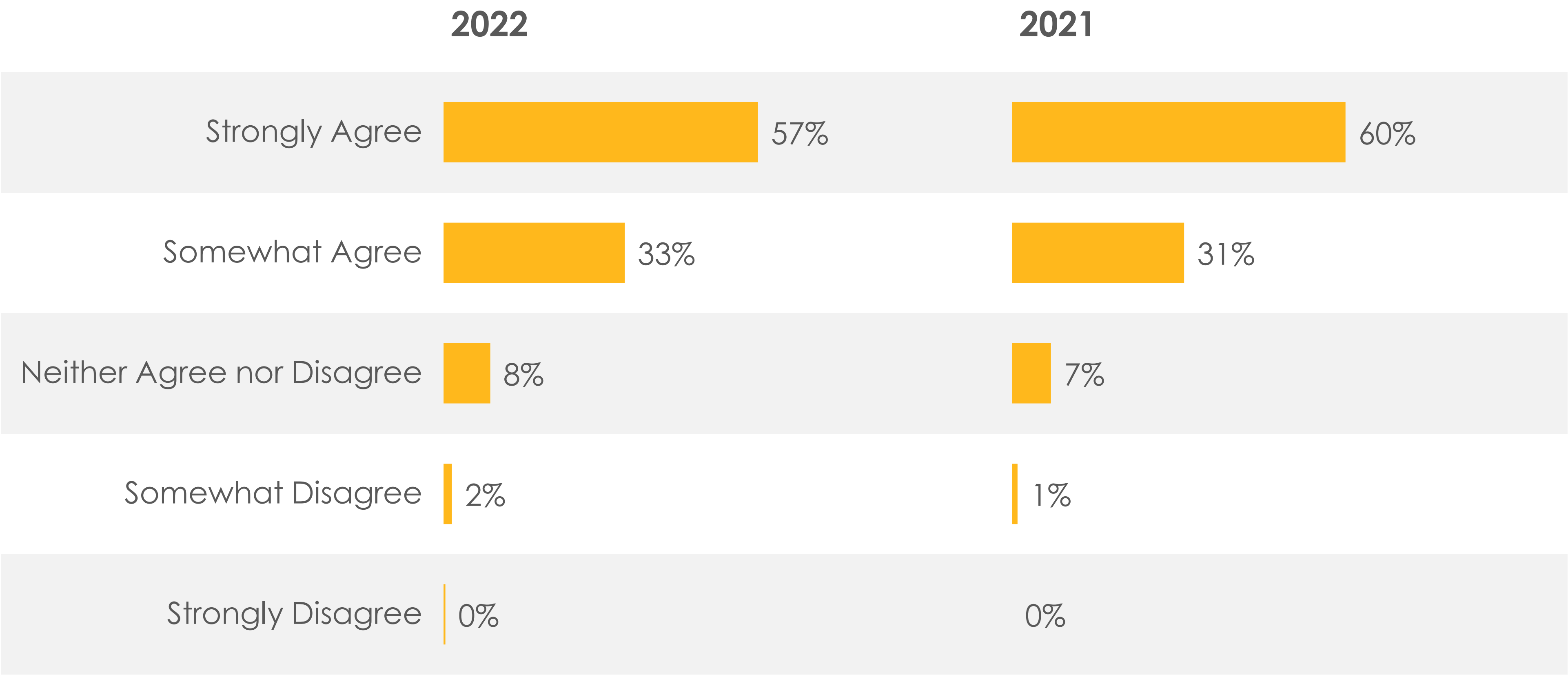


X1-X5. For each of the following questions, please answer true or false.
Base: All respondents 2022 (n=1200); 2021 (n=1200)

Note: Values less than 3% not labelled.

Perceptions of Natural Gas Usage

- The vast majority (89%) of natural gas users feel as though natural gas is safe to use in homes.
- Natural gas users living in the legacy Union Gas territory (60% vs. 54% legacy Enbridge Gas Distribution), the 55+ cohort (62% vs. 47% under 55), and those living in the Windsor/Chatham (70%) and Northwest region (70% vs. 56% across all other regions) are among the most likely to strongly agree that natural gas is safe to use in homes.



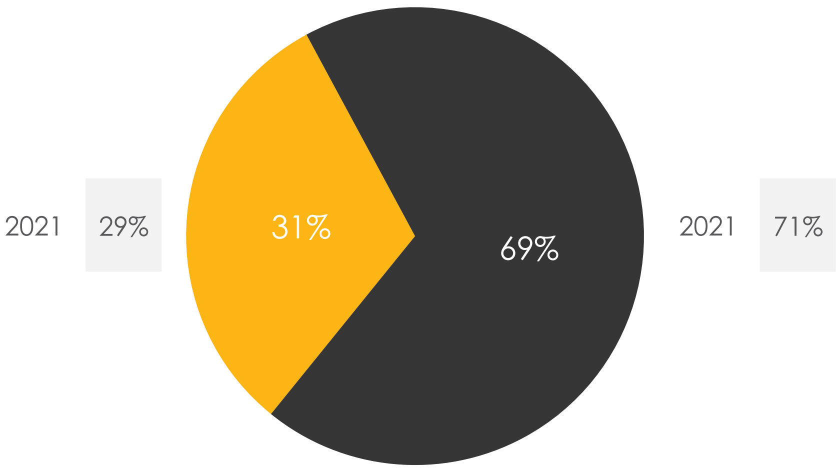
Note: Values less than 4% not shown

QA1. To what extent would you agree or disagree with the idea that natural gas is safe to use in homes?
Base: All respondents 2022 (n=1200); 2021 (n=1200)

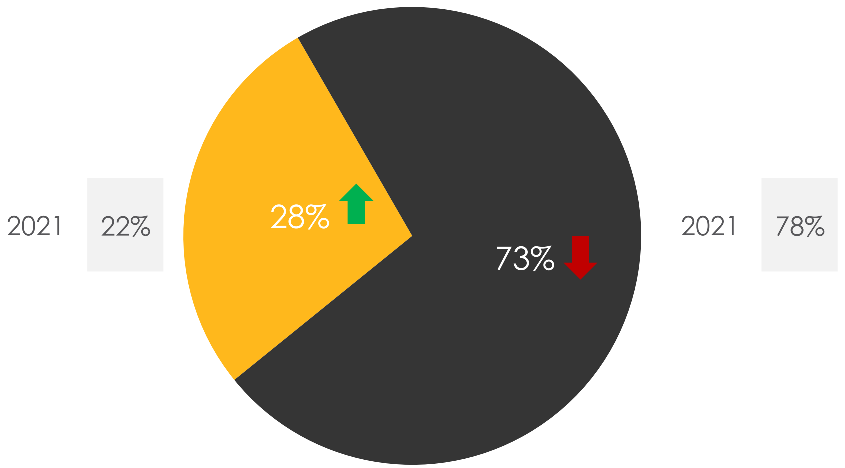
Recall Receiving Natural Gas Safety Information

- Most natural gas users do not recall receiving natural gas safety information via bill insert (69%) or by safety email (73%). However, greater proportion recall receiving natural gas safety information via safety email (28%; +6 pts vs. 2021), relative to the previous year.
- Younger natural gas users (18-34) are more likely to recall receiving natural gas safety information via bill insert (44% vs. 30% 35+). eBill users are more likely to recall receiving this information by safety email (30% vs. 24% of paper bill natural gas users).

BILL INSERT



SAFETY EMAIL



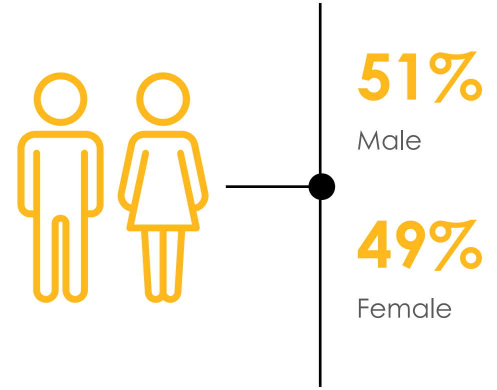
Q16. Do you recall receiving this information with your Enbridge Gas bill?
Base: All respondents 2022 (n=1200); 2021 (n=1200)
Q17. Do you recall receiving this information by email from Enbridge?
Base: All respondents 2022 (n=1200); 2021 (n=1200)

Note: Values less than 4% not shown

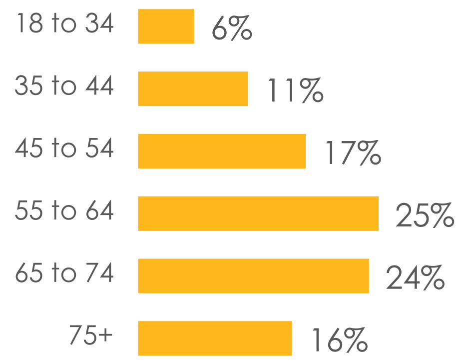
DEMOGRAPHICS

Demographics

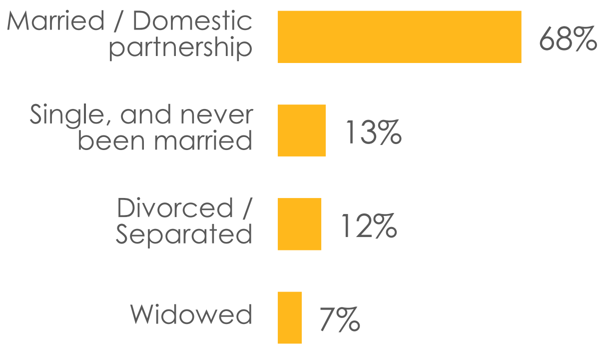
GENDER



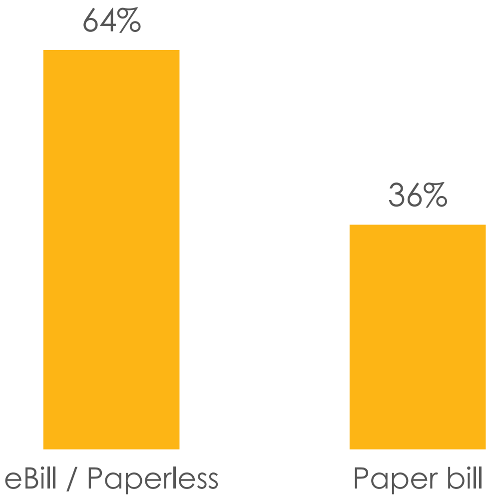
AGE



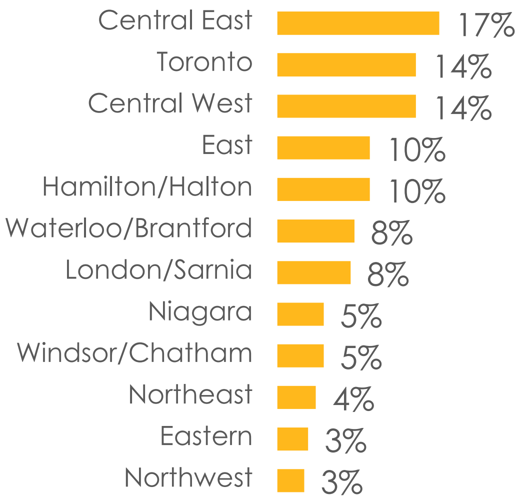
MARITAL STATUS



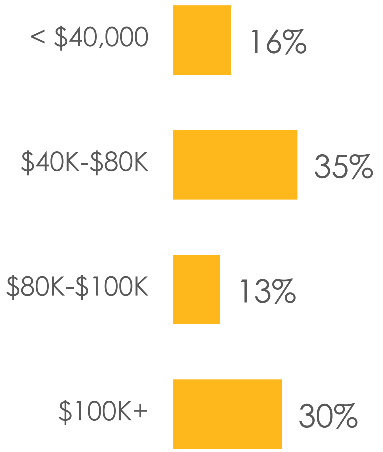
BILL TYPE



REGION

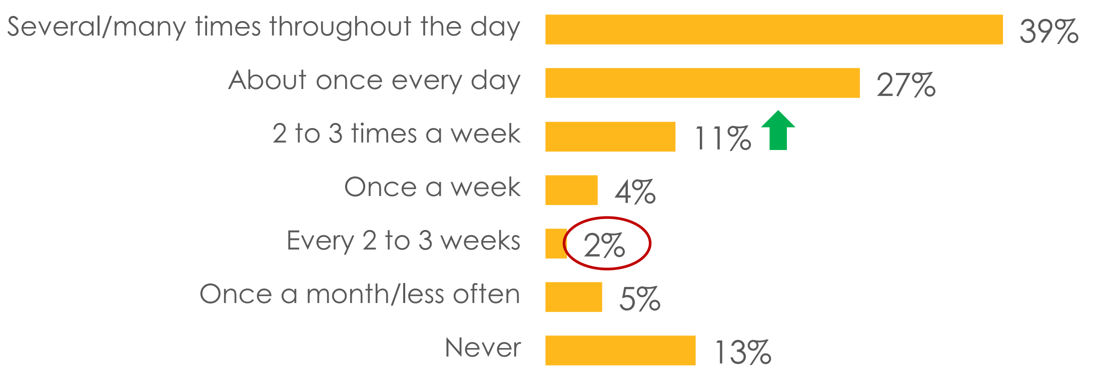


HOUSEHOLD INCOME

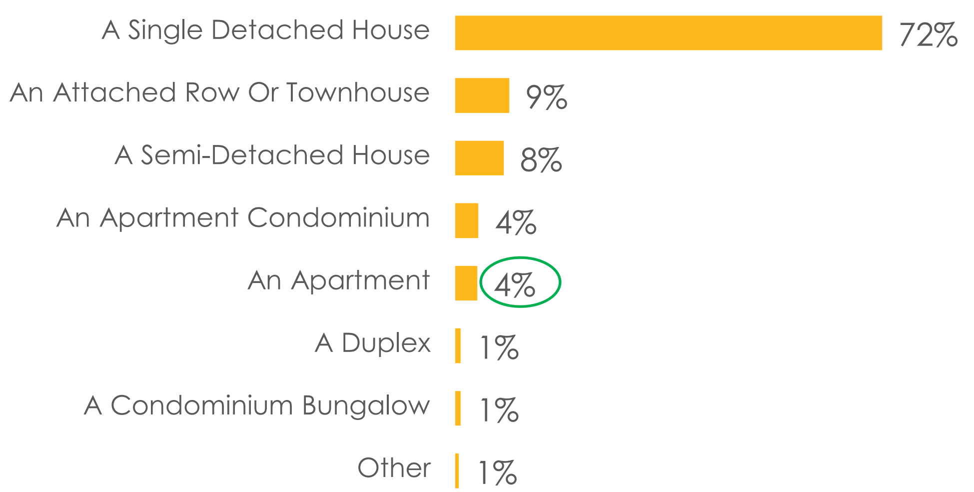


Demographics (cont.)

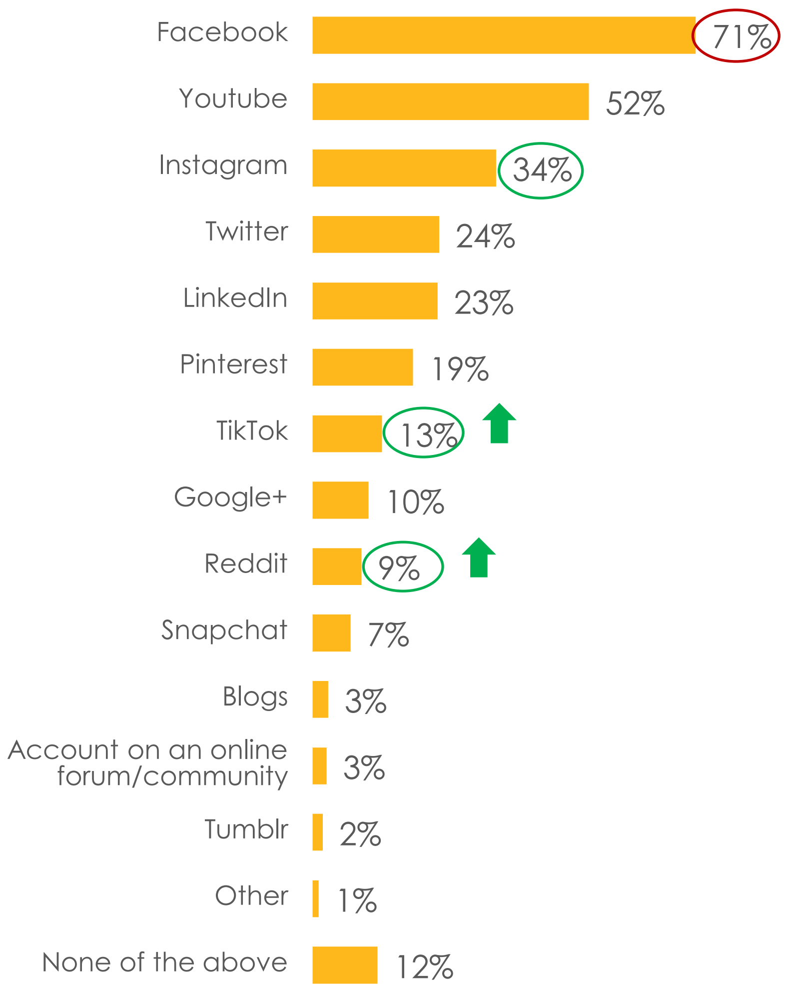
SOCIAL MEDIA USAGE



TYPE OF HOME



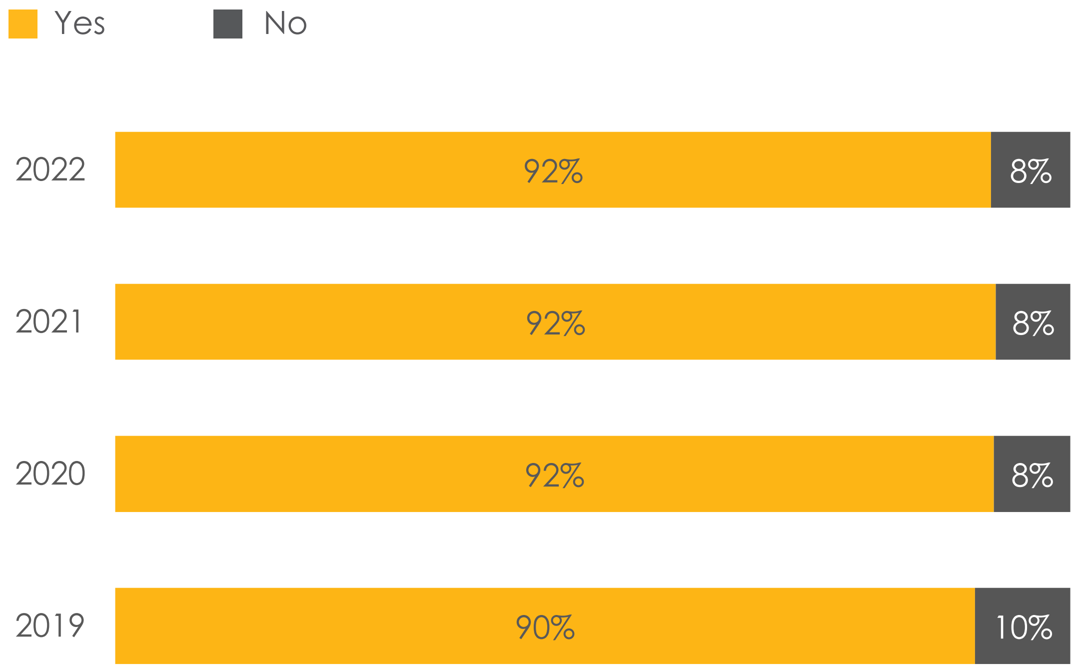
SOCIAL MEDIA USAGE (AT LEAST ONCE / MONTH)



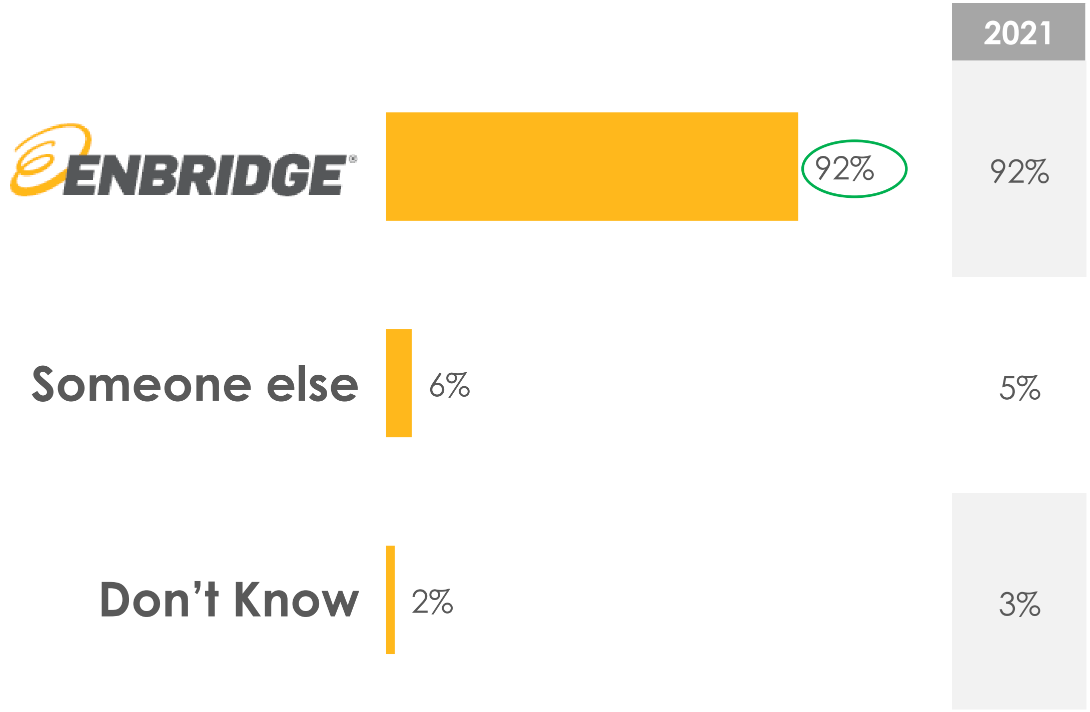
Natural Gas Bill

- On par with previous years, around nine in ten (92%) natural gas users indicate that they receive a natural gas bill, of which a vast majority (92%) indicate that Enbridge is their natural gas provider.

RECEIVE A NATURAL GAS BILL



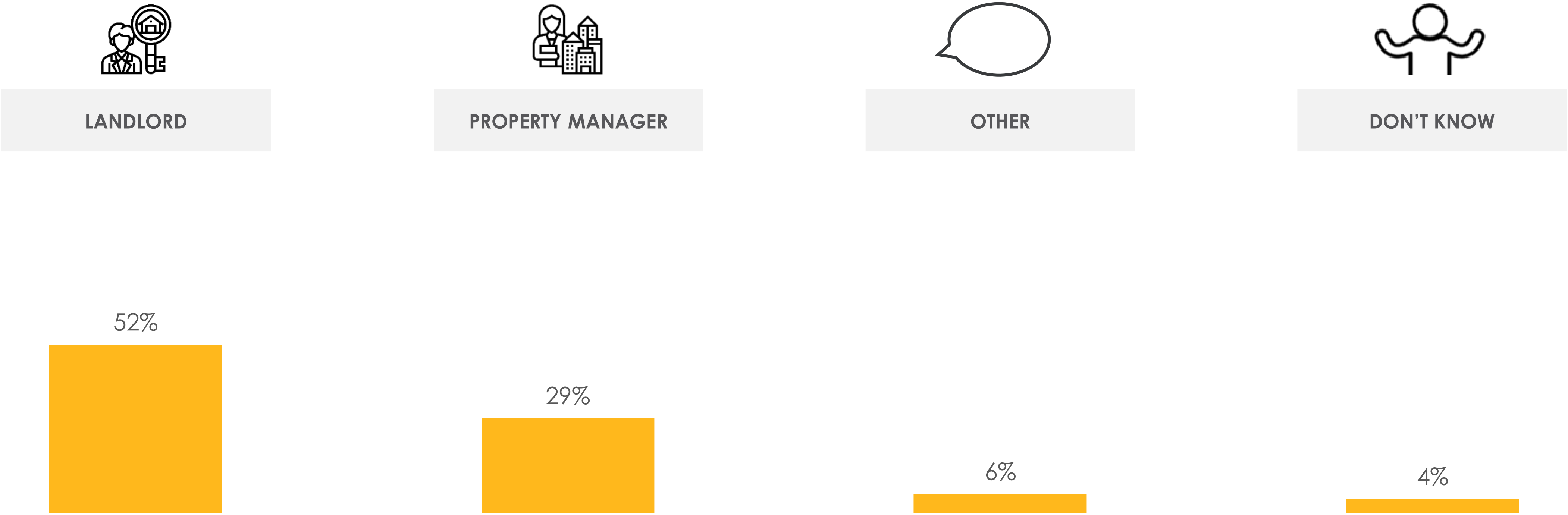
NATURAL GAS PROVIDER



S4. Do you receive a natural gas bill? Base: All respondents; 2022 (n=1200); 2021 (n=1200); 2020 (n=1200); 2019 (n=1200)
S5. From whom do you receive your natural gas bill …? Base: Receive a natural gas bill; 2022 (n=1102); 2021 (n=1104); 2020 (n=1107); 2019 (n=1074)
Note: Union Gas response option was removed at S5 in 2021. Respondents who selected some other natural gas provider were allowed to proceed with the survey in 2021, unlike in previous years.

Natural Gas Bill Reception for MU natural gas users

- A majority (52%) of those who do not receive a bill indicate that it goes to their landlord, while about three in ten (29%) list their property manager as the bill recipient.



	LANDLORD	PROPERTY MANAGER	OTHER	DON'T KNOW
2021	57%	25%	4%	5%
2020	43%	32%	6%	6%
2019	53%	30%	2%	7%

S6. Who receives the natural gas bill?
Base: Do not receive a natural gas bill; Total 2022 (n=98); 2021 (n=96); 2020 (n=93); 2019 (n=126)

Note: Values less than 4% not shown

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You act better when you are sure.

New Housing

Residential Natural Gas End Use Study
2022 Results

ENBRIDGE

Customer & Market Insights
February 2023

2022 Residential New Housing Natural Gas End Use Study

Background

ENBRIDGE

Objectives

- Measure the penetration of natural gas appliances within the franchise “new build” customer base,
- Understand customer perceptions of the energy efficiency levels of their home and their familiarity with energy efficiency rating systems,
- Determine key factors in the home purchase decision,
- Gauge awareness of renewable natural gas, and
- Gauge awareness of solar panels, heat pumps and geothermal.

Methodology

- Respondents are customers who reside in single family dwellings built within the prior 18 months (built after May 2021) and are (mainly) responsible for making energy-related decisions for the home.
- Sponsor identified telephone interviews were fielded by Leger, a Canadian market research vendor, over the period December 16, 2022 - January 12, 2023.
- 801 interviews were completed across the total Enbridge Gas area. Total results are weighted by the total proportion of customers in each franchise area.
- Overall results yield a margin of error of +/-3.4% at the 95% confidence interval.
- Results prior to 2019 are for the LUG (Legacy Union Gas) franchise area only.

2022 Residential New Housing Natural Gas End Use Study

Region Definitions

- Unless otherwise noted, results in this report are based on the total Enbridge Gas area.
- The regions reported in this report are defined as follows:

Region Name	Includes
Northern	Northeast (DMA 46), Northwest (DMA 33)
Eastern	Eastern (DMA 22), DMA 65
GTA West	DMA 17, DMA 21, DMA 53
GTA Toronto	DMA 01
GTA East	DMA 35, DMA 45, DMA 47
Southeast	Waterloo/Brantford (DMA 7), Hamilton/Halton (DMA 16), DMA 76
Southwest	Windsor/Chatham (DMA 2), Sarnia/London (DMA 4)

Executive Summary (1 of 2)

- Natural gas continues to be used for home and water heating for the majority of newly built homes across the franchise area, though it is noted that home heating and water heating have been lower since 2020.
- Custom built homes are more likely to use natural gas for home and water heating compared to tract/production homes or homes that were already completed.
- The use of natural gas to fuel secondary appliances varies:
  - Prevalence of natural gas cooktop/stoves is up slightly in 2022 and is highest in the Southwest region (51%).
  - Compared to previous years, though the same proportion of fireplaces are being installed in new homes, fewer use natural gas.
- Smart Thermostats installed in new homes continue to trend upward and are likely to surpass programmable thermostats in the near future. Most thermostats were included with the home by the builder (80%).
- The proportion of tankless water heaters continues to grow – accounting for over half of all water heaters (56%). Ownership levels have increased over the past few years – and are comparable to 2019 results. The proportion who said builders offered a choice for the fuel type is stable.

Executive Summary (2 of 2)

- About 2-in-5 respondents believe that their home is built to a higher level of energy efficiency (EE) compared to the standard new home built to Ontario Building Code standards, and a similar proportion discussed the home's EE with the builder prior to making the purchasing decision. Most respondents who discussed the home's EE with the builder expressed satisfaction with the usefulness and amount of information provided.
- Among factors that influence the purchasing decision, this year EE is no longer in the top 5 mentions overall, but this varies by region.
- Familiarity with home EE rating systems has moved very little over the past several years, with the majority of respondents being unfamiliar or never having heard of most rating/certification systems. Familiarity with ENERGY STAR sees a declining trend over the past 4 years, and about 1-in-5 respondents indicate seeing some energy efficiency advertising during the process (though this mostly relates to products/appliances).
  - Solar Ready Homes continues to garner greater familiarity than Net Zero (and Net Zero Ready) and Passive Houses however, familiarity with Net Zero and Net Zero Ready homes continues to trend upward, while familiarity with Solar Ready Homes remains stable.

Overview of Natural Gas Appliances

- Natural gas continues to lead as the fuel of choice for home and water heating.
- The prevalence of natural gas appliances in new homes is quite similar across Regions for most appliances. Data for clothes dryers and barbecues was not collected in 2022.

	2014	2015	2016	2017	2018	2019	2020	2021	2022
			LUG			EGI	EGI	EGI	EGI
Home Heating	97%	96%	97%	95%	95%	95%	93%	89%	91%
Water Heating	85%	88%	85%	86%	83%	84%	76%	74%	74%
Fireplace	55%	57%	60%	56%	51%	58%	47%	47%	58%
Stove/Cooktop	39%	46%	48%	53%	41%	44%	40%	38%	42%
Clothes Dryer	10%	16%	20%	17%	15%	13%	8%	5%	--
Barbecue	31%	28%	30%	28%	26%	24%	21%	12%	--

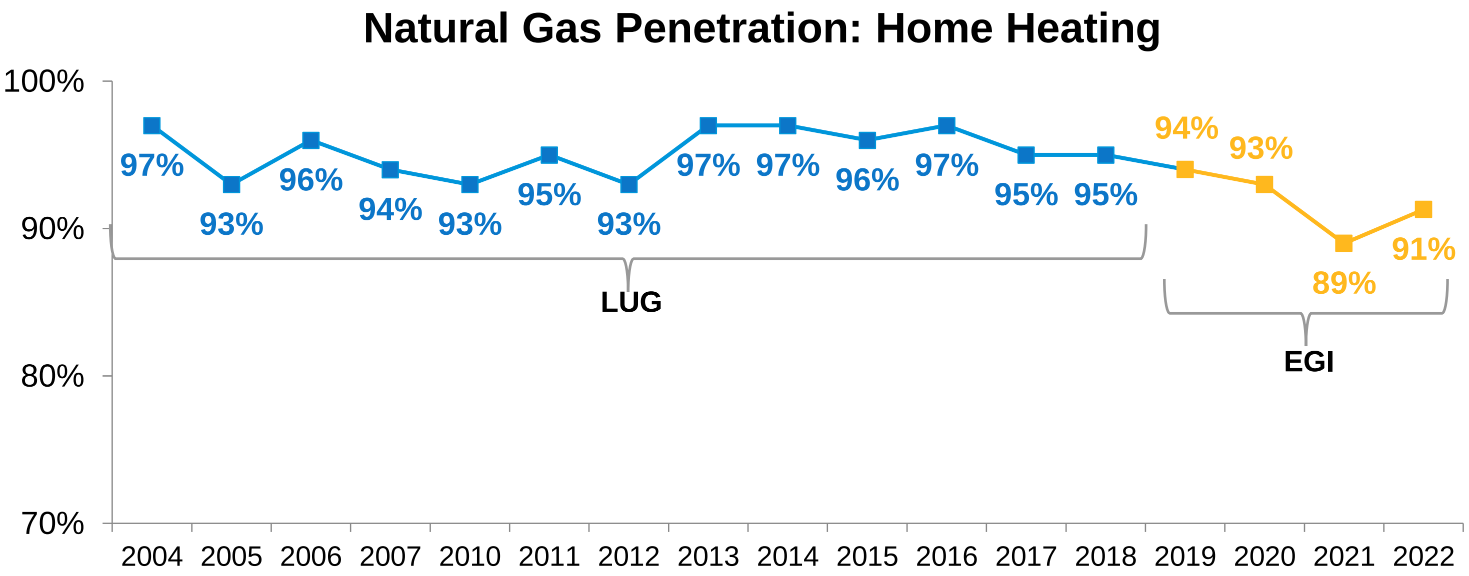
(--) indicates no measurement

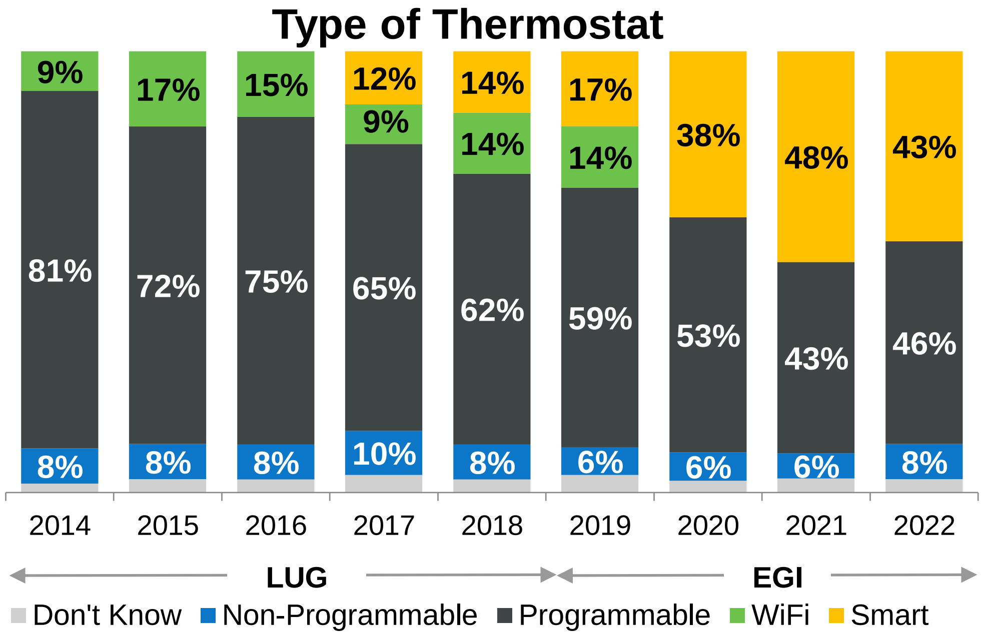
2011-2014 results for Outdoor BBQs restated on full population base size for consistent comparison.

2022 Residential New Housing Natural Gas End Use Study

Home Heating: Gas Adoption & Equipment

- Natural gas continues to be the dominant choice for home heating – the remainder tend to heat with electricity (8% for EGI).
- Heating equipment continues to be predominately forced air (66%) though it is noted that a sizable group of respondents are not aware of the specific type of heating equipment in their home (21% Don't Know).
  - A sizeable proportion of respondents in the Northern region reported a hydronic (Hot Water Radiators) (11%) or a combination system that provides both space heating and hot water (11%).
- Smart thermostats have been trending upward since Enbridge Gas started collecting information. Most thermostats were included with the home (80%), while the remainder were purchased and installed by the customer.





Q:What is the MAIN energy source for heating your home? Q: What type of natural gas furnace or heating system do you have? Is it a forced-air system, a hydronic system using a hot water radiator, a space heater, or a combination system where the water heater, rather than a furnace, heats your home? Q: Which of the following thermostats do you have? Q: Was this thermostat included with the home or did you purchase and install a new one when you moved?

Fireplace: Gas Adoption & Equipment

- The percentage of respondents with a fireplace remain unchanged. Just over half of respondents have a fireplace (57%) – among them, the majority have just one. Fireplaces are especially popular in GTA East (69%), Eastern (62%), and GTA West (60%).
- The majority have fireplaces are fueled natural gas (74%), followed by electricity. Electric fireplaces significantly increased in popularity over the past 4 years.
- Almost 1-in-6 respondents are likely (fairly/very/extremely) to install an indoor fireplace in the next 2 years – among them most would install electric (51%) followed by natural gas (44%).

Do you have an indoor fireplace?	EGI
Yes	57%
… One	51%
… Two or more	5%
No	43%

Any fueled by …	EGI
Natural Gas	74%
Electricity	27%
Wood	1%

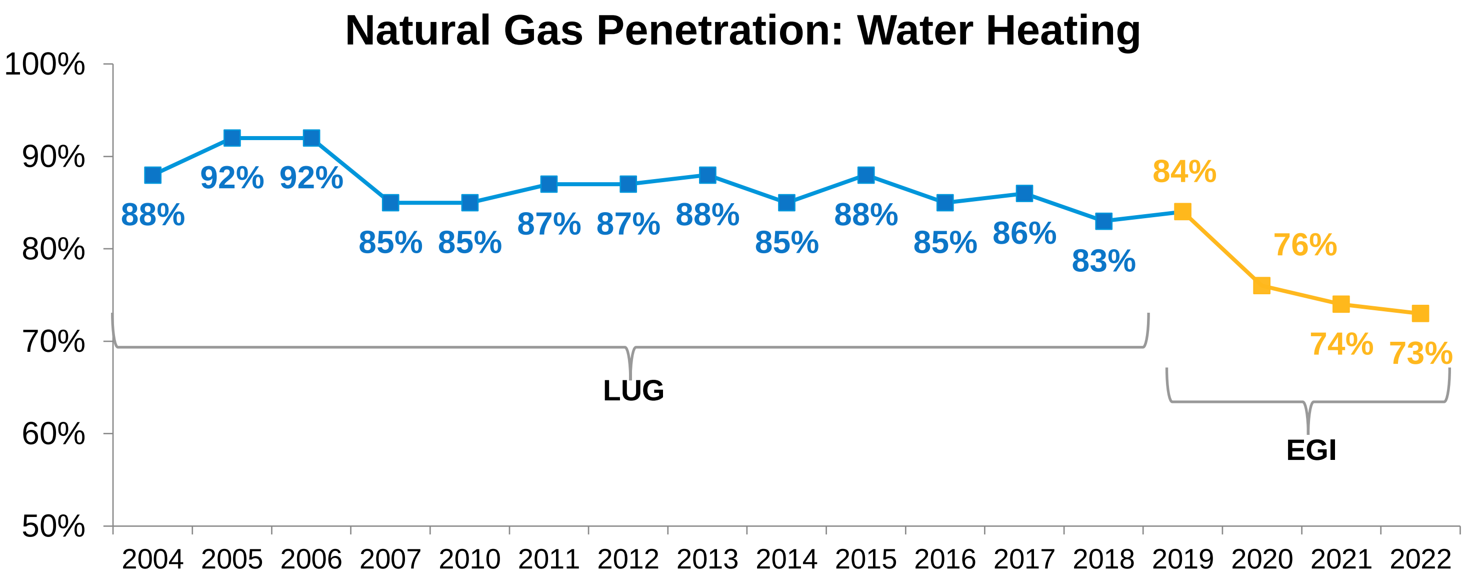
Likely to install an indoor fireplace in the next 2 years (and what fuel)	EGI
Extremely / Very / Fairly Likely	15%
… Natural Gas	44%
… Electric	51%
… Other	5%
Not very / Not at all Likely	83%
Don't Know	2%

Q: Are there any indoor working fireplaces in your home? Q: How many indoor working fireplaces do you have in your home? Q: And which energy source does (FIREPLACE #) use? Q: How likely are you to install an indoor fireplace in your home in the next 2 years? Are you ... Q: And what type of fireplace are you most likely to install?

2022 Residential New Housing Natural Gas End Use Study

Water Heating: Gas Adoption & Equipment

- Natural gas continues to be the most popular option for water heating (73%), though penetration continues to soften.
- About 1-in-5 respondents say their builder offered them a choice in the type of water heater installed. Respondents in the Northern region are more likely to be offered a choice of water heater (47%) followed by Southwest (27%).
- Over half of respondents have a tankless water heater - they are much more popular in the Eastern (68%) and Southwest (66%) regions.
- Ownership rose to over 1-in-4 (27%) compared to last year (14%).



Builder offered a choice between Natural Gas and Electricity …	EGI
Yes	17%
No	76%
Don't Know	7%
Type of Water Heater	**EGI**
Tank	42%
Tankless	56%
Don't Know	2%
Ownership of Water Heater	**EGI**
Owned	27%
Rented	72%
Don't Know	1%

Q: What type of water heater do you have? Is it ...? Q: Did the builder allow you to choose the fuel you would prefer your water heater to be powered by?
Q: Does your water heater have a tank or is it tankless? Q: Is your water heater owned or rented?

2022 Residential New Housing Natural Gas End Use Study

Cooking: Gas Adoption & Equipment

ENBRIDGE

- About 3-in-4 respondents have a stove. Stoves are more prominent in the Eastern (84%) and Northern regions (86%). Cooktop/countertop ranges are more prevalent in the GTA Toronto region (56%).
- Natural gas cooking appliances are more popular in the Southwest region (51%), followed by the Southeast region (49%).
- Most stoves are bought new by the customer or are part of the builder's incentives. The same is true for cooktop/countertop ranges. Among those who had the stove included as part of the builder incentives, 10% paid extra for an upgrade.

Do you have a …	EGI
Stove	76%
Cooktop / Countertop range	25%
Separate built-in oven	12%

Fueled by Natural Gas (%)	EGI
Stove	40%
Cooktop / Countertop range	46%
Separate built-in oven	11%

Stove was …	EGI
Brought the OLD one	2%
Purchased a NEW one	73%
INCLUDED as part of the builder incentives	23%
Already in the home/Purchased with the home	1%

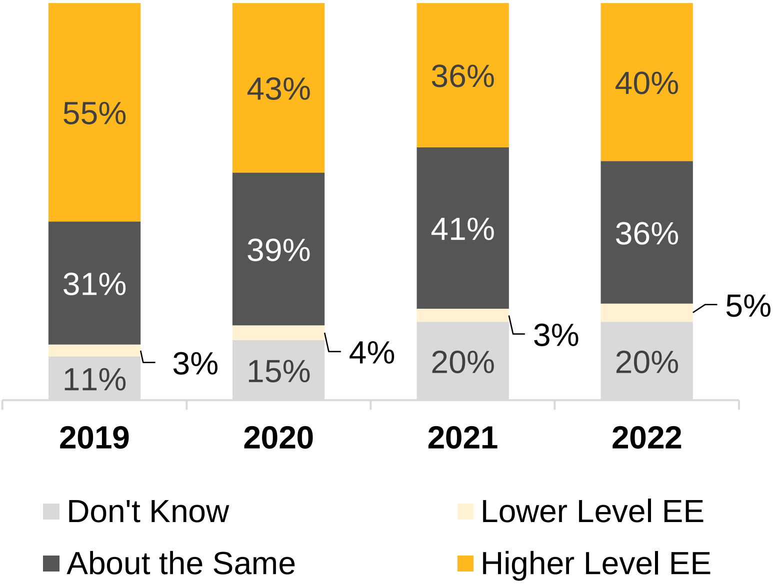
Q: Do you have a stove, or do you have a cook top with a separate oven? Q: Is your stove / cooktop / counter range / separate built-in oven fueled by natural gas or electricity? Q: Did you bring your stove / cooktop / counter range / separate built-in oven from a previous home or did you purchase a new one when you moved? Q: Was the stove / cooktop / counter range / separate built-in oven included as part of the builder incentives or did you have to pay extra for an upgrade? Q: Assuming your stove / cooktop / counter range / separate built-in oven does not break down, how likely are you to replace it in the next 2 years? Are you...? Q: What type of stove / cooktop / counter range / separate built-in oven are you most likely to replace your current appliance with?

2022 Residential New Housing Natural Gas End Use Study

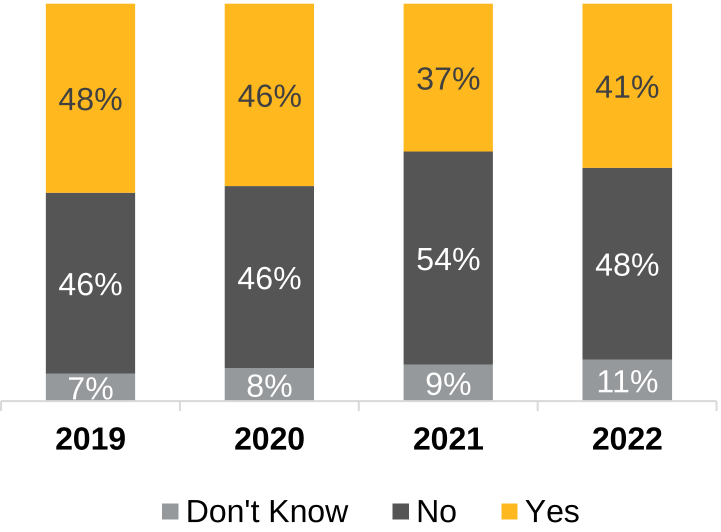
Energy Efficiency (EE) of the New Home

- Most respondents believe their new home is built at least to the same level of EE, if not higher, compared to a standard new home (built to Ontario Building Code standards). It is worth noting that perceptions of homes being built to a higher level of EE are showing signs of softening.
- The belief that the home is built to higher EE levels is significantly more prevalent among those who have a custom-built home (65% say their house is built to a higher level of EE compared to 40% overall).
- About 2-in-5 customers say their builder discussed the home's EE prior to making the purchase decision – this continues to vary by region

Level of Home EE (compared to standard new house built to OBC)



Builder discussed EE prior to making purchase decision



Region	Yes (%)
Northern	64%
Eastern	42%
GTA West	37%
GTA Toronto	22%
GTA East	37%
Southeast	36%
Southwest	51%

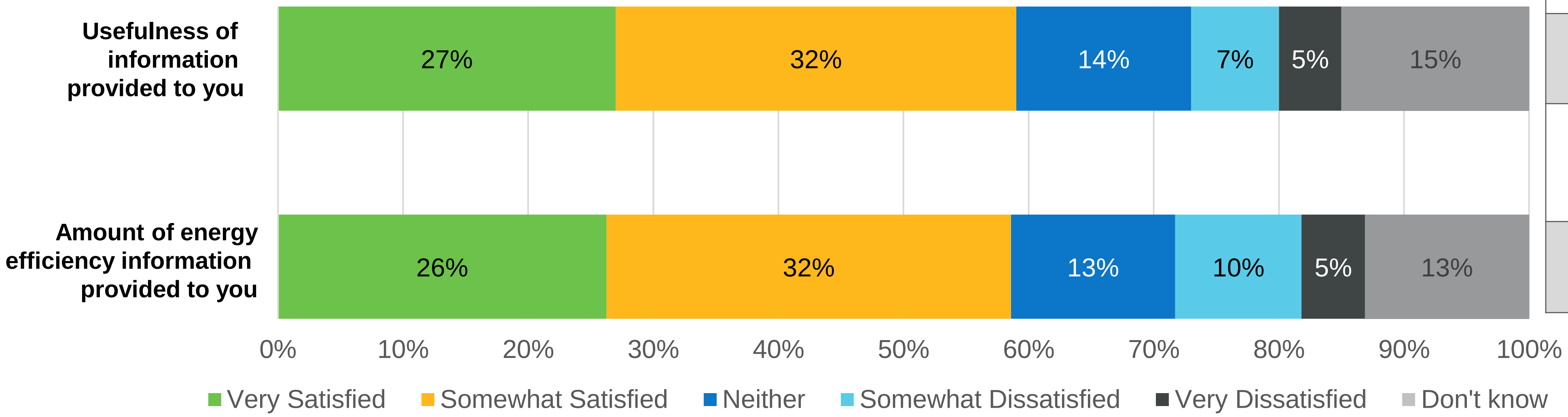
Q: To the best of your knowledge, and compared to the standard new home built to the Ontario Building Code standards, is your new home built to a… ? Q: Prior to making your purchase decision, did the builder discuss the home´s energy efficiency with you?

2022 Residential New Housing Natural Gas End Use Study

Home Energy Efficiency: Satisfaction with EE information provided

- Most respondents indicate satisfaction with the usefulness and amount of energy efficiency provided during the decision-making process (though more than 1-in-10 indicate some dissatisfaction).
- Satisfaction on these measures is stronger among Northern and Southwest regions. Similarly, satisfaction is also stronger among those who discussed energy efficiency with the builder.

Satisfaction with Energy Efficiency Information Provided During Decision-Making Process



Total Satisfied (Top 2 Box %)	
Total	The builder discussed EE with you (Yes)
59%	86%
59%	87%

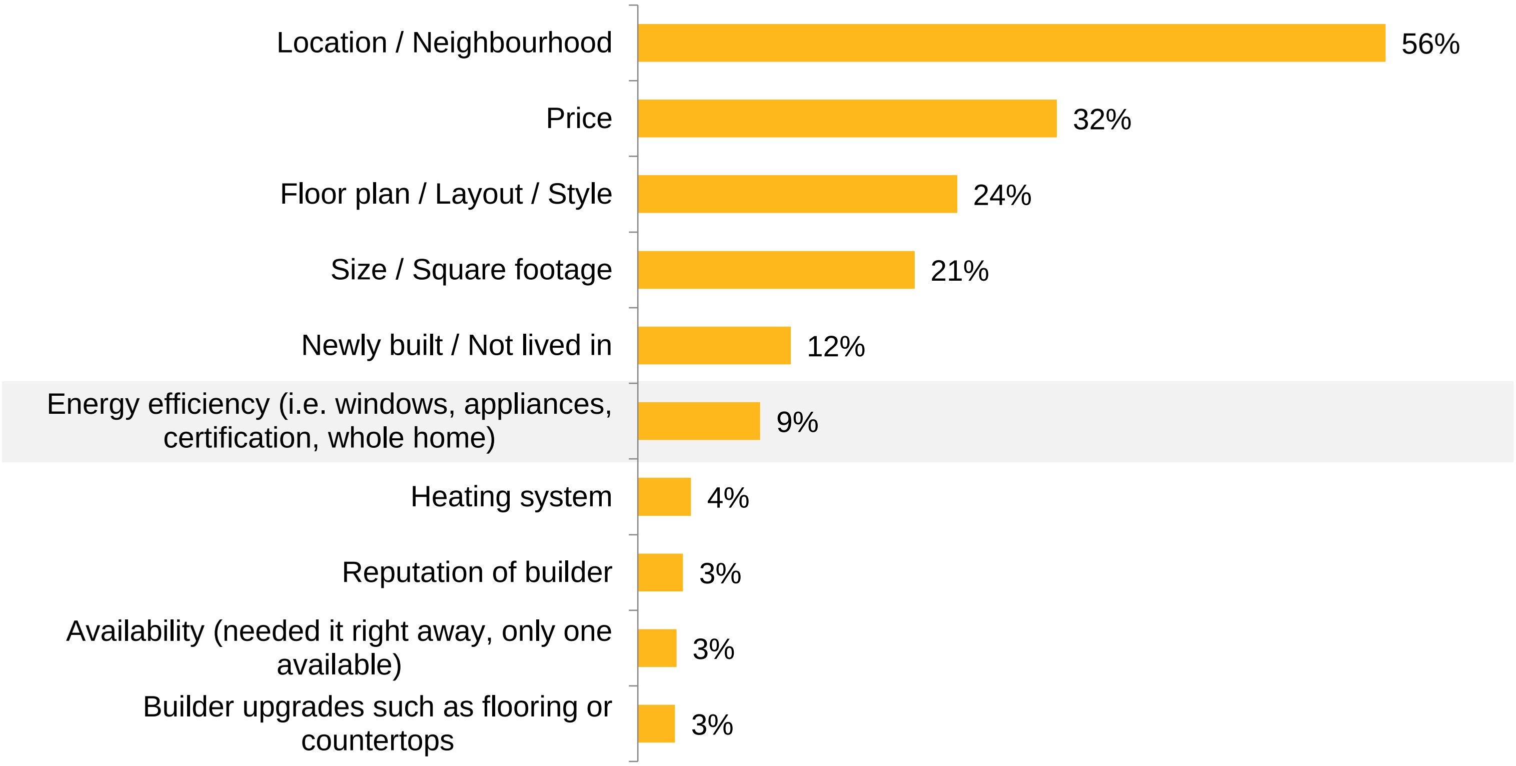
Q: Thinking about the energy efficiency information provided to you during the decision-making process, how satisfied were you with the following:

2022 Residential New Housing Natural Gas End Use Study

Factors in Home Purchase Decision

- Location, floor plan (as well as size) and price continue to be top factors that influence the home purchase decision.
- About 1-in-6 respondents identified energy efficiency as a top factor in the purchase decision. Energy efficiency is a more prominent factor for the Northern region.

Factors Important in Choosing a New Home *(Unaided)*



Region	Energy Efficiency (%)
Northern	19%
Eastern	13%
GTA West	7%
GTA Toronto	6%
GTA East	3%
Southeast	5%
Southwest	10%

Q: Please tell me what factors were important when you chose your new home?

2022 Residential New Housing Natural Gas End Use Study

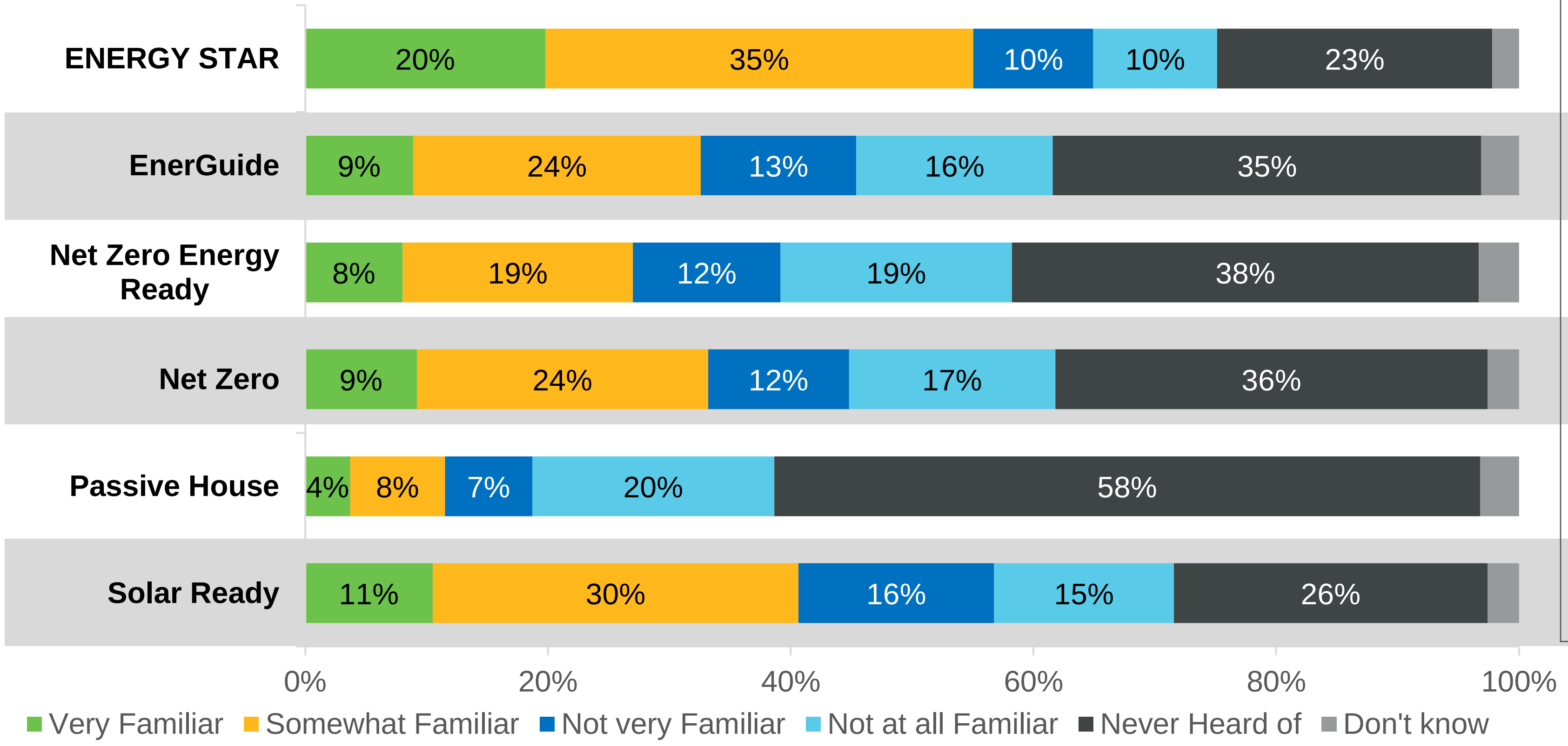
Familiarity with Energy Rating Systems

ENBRIDGE

- Familiarity with energy rating systems is fairly stable compared to 2021 results.
- Respondents are most likely to be familiar with “ENERGY STAR” for new homes (55%) followed by “Solar Ready” homes (41%).
- Among certifications, respondents are most likely to believe their home is certified or labelled as “ENERGY STAR” (39%).

Familiarity with rating systems

(base: all new housing customers)



	Top 2 Box (Very + Somewhat)		Is your home certified? (base: all homes)	
	2022	2021	2022	2021
ENERGY STAR	55%	63%	39%	38%
EnerGuide	33%	35%	25%	24%
Net Zero Energy Ready	27%	25%	7%	3%
Net Zero	33%	33%	7%	4%
Passive House	12%	11%	5%	3%
Solar Ready	41%	43%	4%	5%

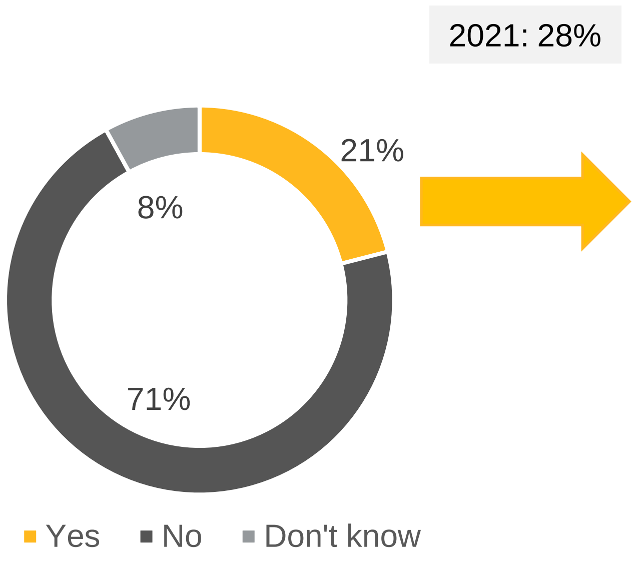
Q: How familiar would you say you are with the following … Q: Is your home certified or labelled by one the following …?

2022 Residential New Housing Natural Gas End Use Study

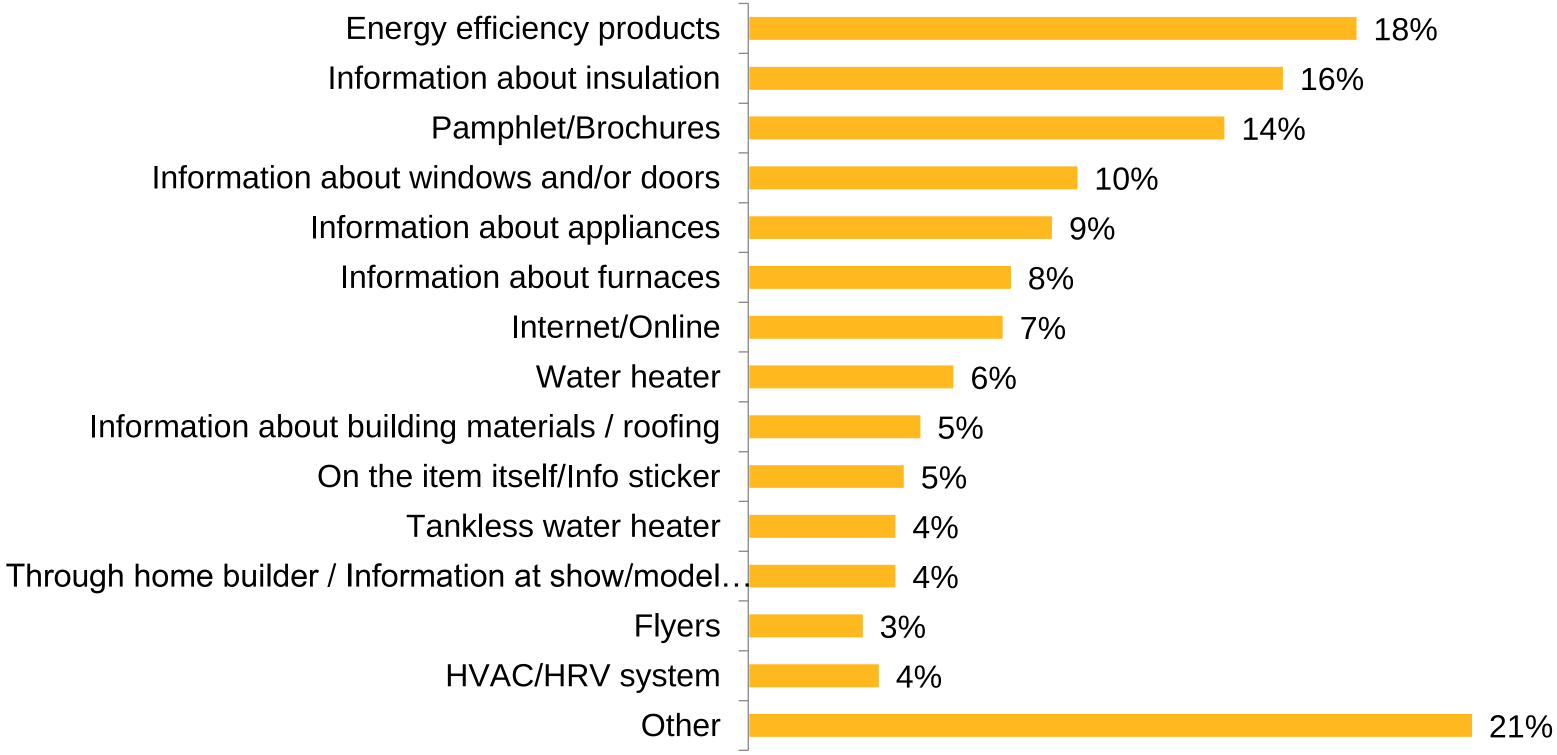
Energy Efficiency Advertising

- About 1-in-5 respondents saw some type of energy efficiency advertising during the home purchasing process. Recall level was strongest in the Northern (31%) and Southwest regions (25%).
- Respondents remember seeing information about energy efficiency products, information about insulation or through pamphlets and stickers, for example.

Saw any energy efficiency advertising for new homes
(base: all customers)



Recall of type of material
(base: all customers who saw advertising)



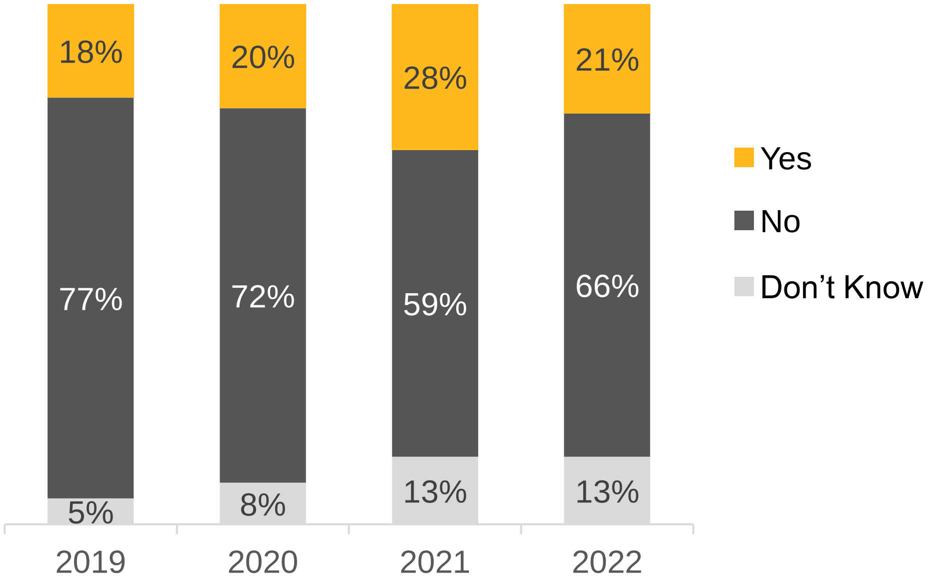
Q: Did you see any advertising material related to energy efficiency during the time you were making your purchase decision? Q: Can you recall what type of material you saw?

2022 Residential New Housing Natural Gas End Use Study

Home Energy Efficiency: Future Intentions

- A portion of respondents (21%) intend to make their new home more energy efficient in the next 2 years.
- The proportion is slightly higher among respondents in tract/production homes (26%) and larger homes that are more than 2,000 sq ft in size (49%).
- Age is also a factor – younger customers are more likely to plan to make their homes more energy efficient than older customers.
- A higher proportion of respondents in the GTA West region indicated plans to make their new homes more energy efficient (32%).

Plan to make home more energy efficient in the next 2 years



Age Group	Yes (%)
18 – 34	28%
35 – 54	24%
55 – 64	8%
65+	2%

Region	Yes (%)
Northern	8%
Eastern	21%
GTA West	32%
GTA Toronto	11%
GTA East	21%
Southeast	22%
Southwest	16%

Q: Do you have any plans to make your home more energy efficient within the next two years?

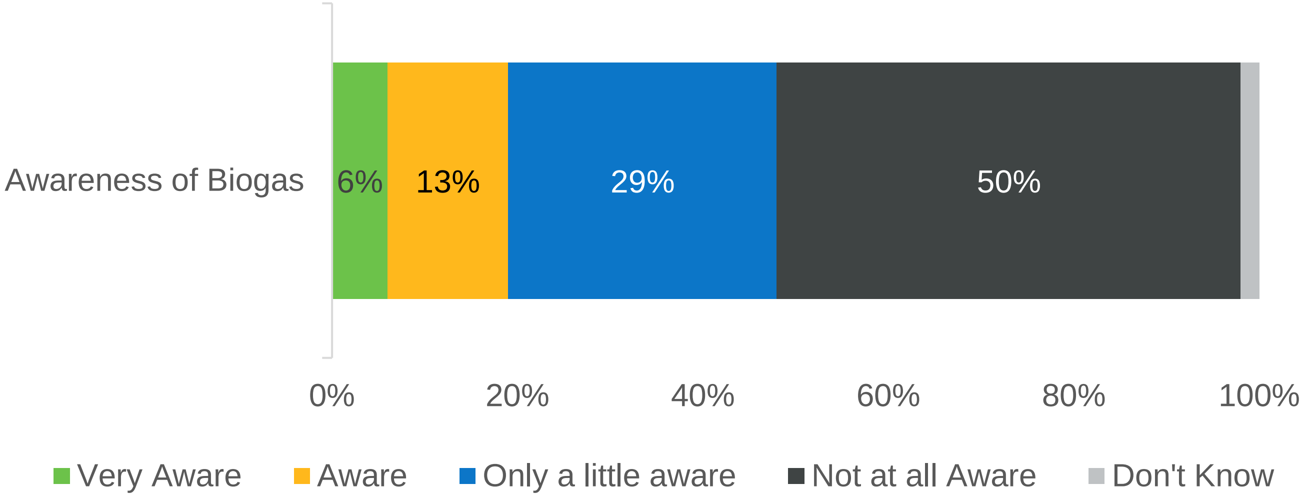
2022 Residential New Housing Natural Gas End Use Study

Awareness of Renewable Natural Gas (Biogas)

ENBRIDGE

- About 1-in-5 respondents are aware of renewable natural gas.
- Awareness level varies by age and region. Those in the Southwest region are more aware of biogas and respondents between the ages of 35-64 have a higher level of awareness of biogas as well.

Awareness of Renewable Natural Gas (Biogas)
(base: all new housing customers)



	Age Group	Aware of Biogas (Top 2 Box %)
	18 – 34	15%
	35 – 54	21%
	55 – 64	24%
	65+	19%

Region	Aware of Biogas (Top 2 Box %)
Northern	14%
Eastern	20%
GTA West	20%
GTA Toronto	17%
GTA East	14%
Southeast	18%
Southwest	25%

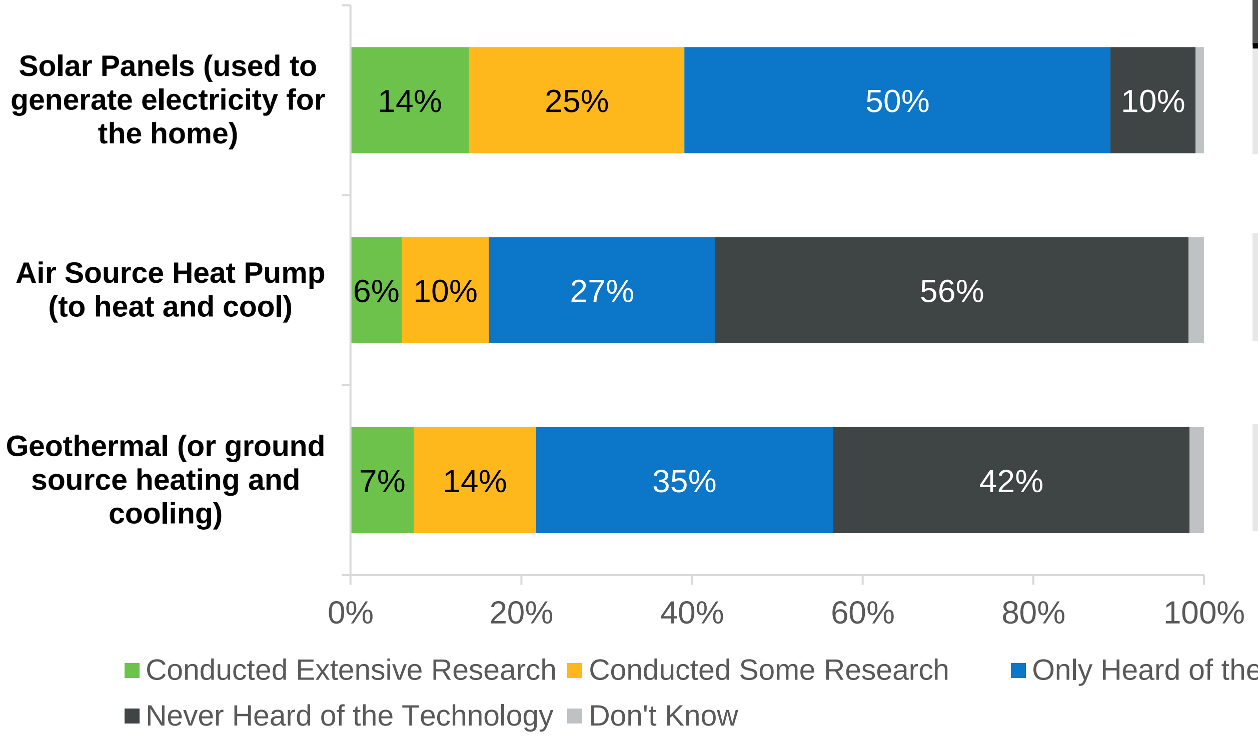
Q: How aware would you say that you are about renewable natural gas, this is sometimes also referred to as bio methane gas, or biogas?

2022 Residential New Housing Natural Gas End Use Study

Knowledge of Technology

- New for 2022 – respondents were asked to rate their level of knowledge with three technologies.
- Respondents in the Northern region were most likely to have conducted at least some research on heat pumps.

Knowledge of Technology for the Home
(base: all new housing customers)



Top 2 Box (Conducted Extensive/Some Research)
39%
16%
22%

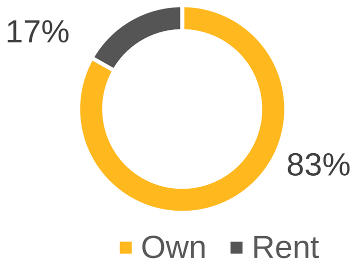
Region	Never Heard of the Technology (%)		
	Solar Panel	Air Source Heat Pump	Geo-Thermal
Northern	6%	36%	17%
Eastern	7%	48%	38%
GTA West	12%	72%	51%
GTA Toronto	33%	61%	67%
GTA East	10%	60%	39%
Southeast	11%	63%	48%
Southwest	10%	50%	40%

Q: Please tell me which of the following statements best describe your knowledge with the following technologies?

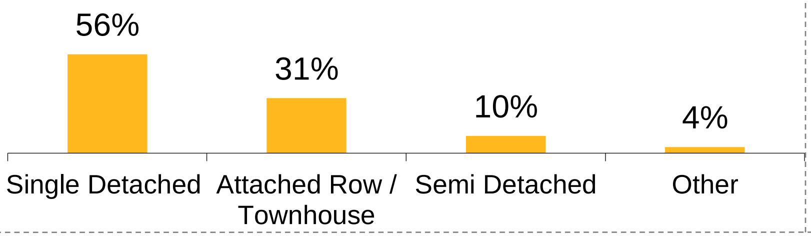
2022 Residential New Housing Natural Gas End Use Study

Demographics: House Characteristics

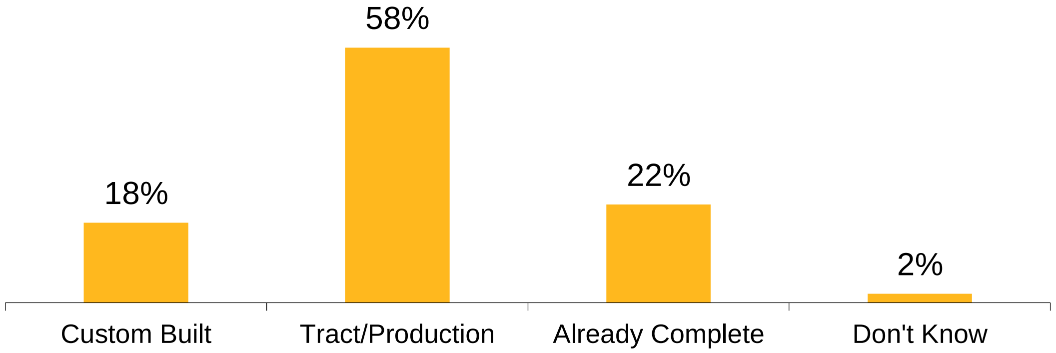
Home Ownership



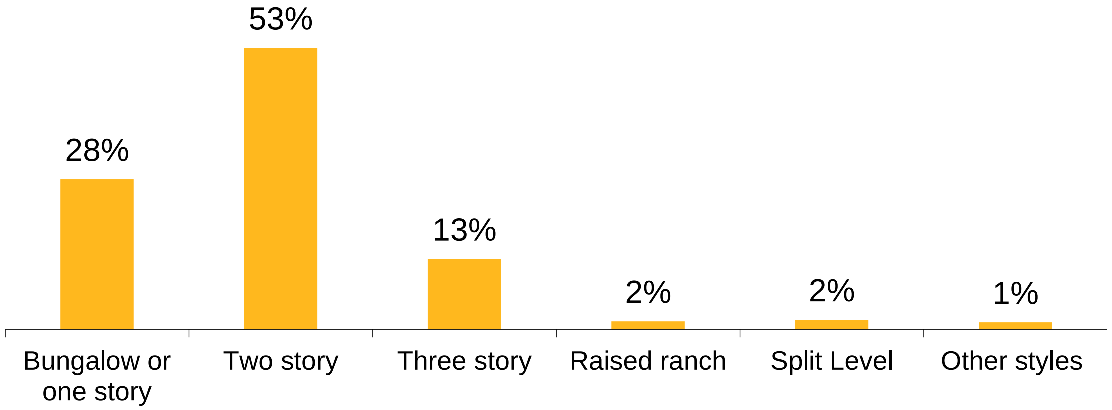
Home Type



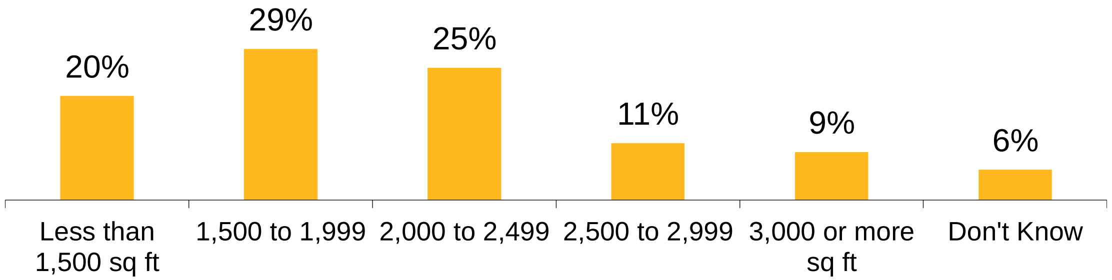
Type of Construction



Style of Home



Size of Home

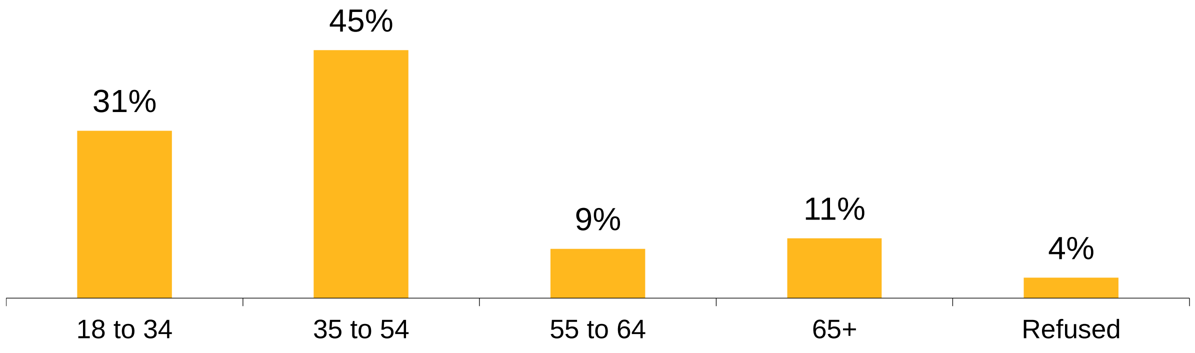


2022 Residential New Housing Natural Gas End Use Study

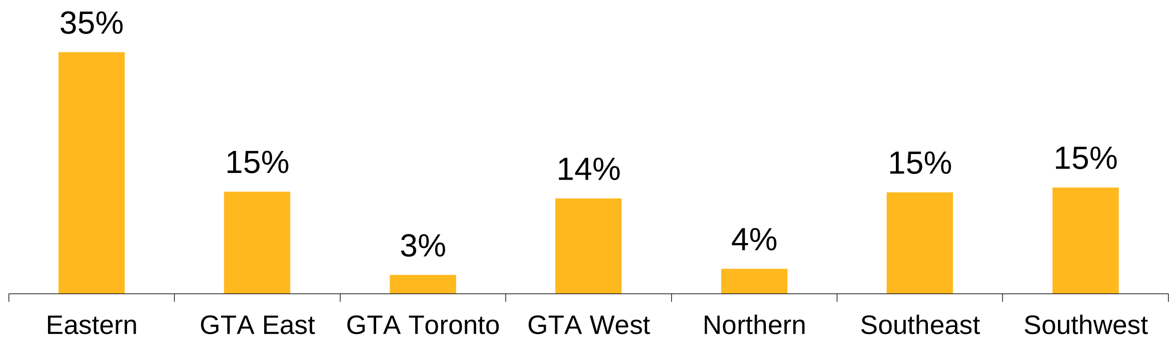
Demographics: Respondent Characteristics

ENBRIDGE

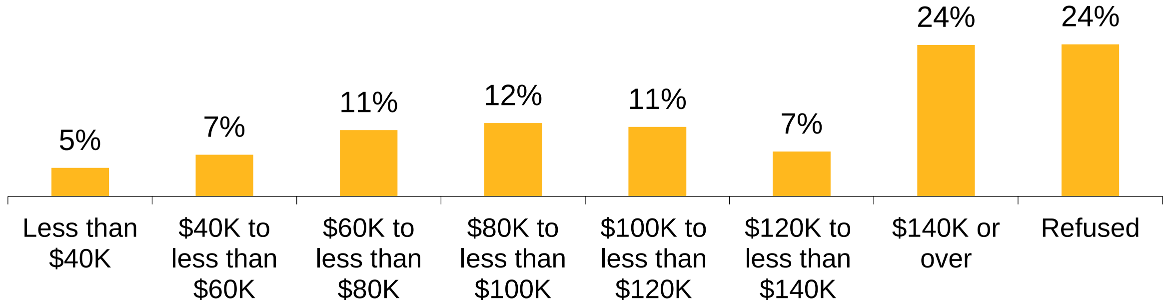
Age



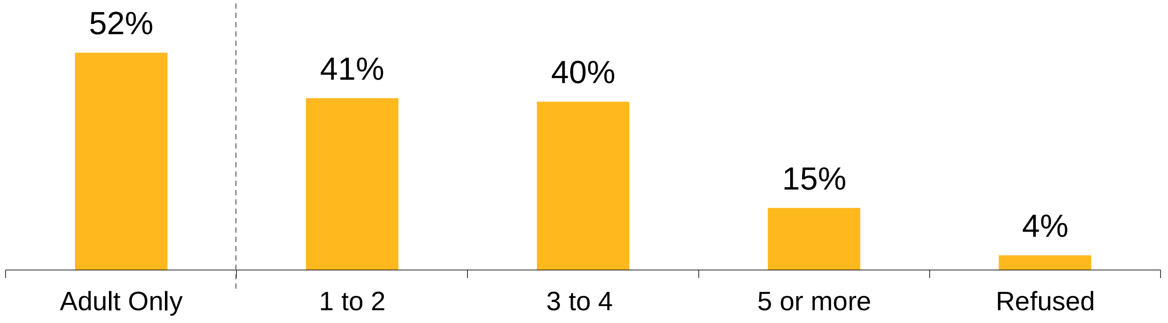
Region



Household Income



Household Size



ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-6-1, Attachment 1

Question(s):

Please provide a copy of all versions of workbooks and surveys provided to customer engagement participants.

Response:

Please find the following versions of workbooks and surveys provided to customer engagement participants in Attachment 1:

- 2024 Rate Rebasing – Customer Engagement Phase II: Refinement Questionnaire
- Customer Engagement Phase III: General Service (Residential) Workbook
- Customer Engagement Phase III: General Service (Business) Workbook
- Customer Engagement Phase III: Contract Customer Workbook
- Rebasing Customer Engagement: Transportation Workbook
- Rebasing Customer Engagement: Producer (M13) Workbook

2024 Rate Rebasing – Customer Engagement Phase 2: Refinement Questionnaire

Telephone & Online Survey

Enbridge Gas Inc.
50 Keil Drive North
Chatham, ON N7M 5M1

Prepared by:

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Toronto, ON | M5E 1A7

Survey Design

Method: Online and Telephone
Language: English
Sample Size: See table below
Sample Frame: Residential Customers who are responsible for paying the bill and Commercial Customers who are responsible for decisions regarding their natural gas account

Sample Design

Customer Segments	Methodology	Sample Size
Residential	Phone and Online	2400 online, 600 phone
Commercial (Small, Billed)	Phone and Online	200 total
Commercial (Medium/Large, Billed)	Phone and Online	200 total

Sample Variables

1. **Type of customer (CUSTOMER) (Residential (CUSTOMER=1) vs Commercial (CUSTOMER=2))**
2. **Type of Commercial customer (Small vs Medium/Large)**
3. **For Residential customers – E-billing (Y/N)**
4. **Consumption**
5. **Legacy Utility**
6. **Region**

Notes:

- This document contains the survey questions asked of both residential and commercial customers. There are some minor differences in wording and in the actual questions, as noted herein.
- This document contains both the online (longer) and telephone (core questions only) versions of the survey. Minor wording changes were made in the programming of the surveys to make the language appropriate for each mode of data collection. For example, "I am going to read you a list…" in the telephone version was changed to "Below is a list …" in the online version.

Email Invitation Sent by Enbridge Gas – Residential

Subject: Enbridge Gas is planning! Your Opinion Matters!

Dear [FULL NAME FROM SAMPLE],

Enbridge Gas Inc. is undertaking a Customer Engagement process that is designed to understand customers' needs and preferences as it develops its investment plans for 2024 and beyond. The goal of this process is to understand the specific outcomes that are valued by customers like you and to consider these when making key business decisions. Your rates may be impacted by this plan so please take this opportunity to have a say.

For this survey, we would like to hear from someone in your household who is responsible or jointly responsible for decisions regarding natural gas such as viewing and paying your natural gas bill. If that is not you, please forward this email to the appropriate person.

As an Enbridge Gas customer, you are invited to complete an online survey. This survey will take approximately 15 minutes to complete, and if you're unable to complete it in one session, you can pick up where you left off by clicking the survey link again – your progress will be saved. We kindly ask that you complete the survey prior to August 22, 2021 by clicking the link below.

Start Survey

To ensure all responses are kept anonymous and confidential, all survey responses will be collected by INNOVATIVE Research Group, an independent market research company. If you would like to verify the authenticity of this survey or would like more information about the survey you can contact marketresearch@enbridge.com.

If you have any problems with the above link please copy and paste the following address into your web browser.

Survey Link: >>>>

Many thanks in advance for your time and input into this planning process.

Enbridge Gas Inc.

Please do not "**Reply**" to this email. This mailbox is not regularly monitored. To stop receiving invitations for our online surveys, please click here to unsubscribe. Your privacy is important to us. For more information please review our Privacy Policy.

Email Invitation Sent by Enbridge Gas – Commercial

Dear [FULL NAME FROM SAMPLE],

Enbridge Gas Inc. is undertaking a Customer Engagement process that is designed to understand customers' needs and preferences as it develops its investment plans for 2024 and beyond. The goal of this process is to understand the specific outcomes that are valued by customers like you and to consider these when making key business decisions. Your rates may be impacted by this plan so please take this opportunity to have a say.

For this survey, we would like to hear from the person in your organization who is responsible or jointly responsible for decisions regarding your natural gas account. If that is not you, please forward this email to the appropriate person. As an Enbridge Gas customer, you are invited to complete an online survey. This survey will take approximately 15 minutes to complete, and if you're unable to complete it in one session, you can pick up where you left off by clicking the survey link again – your progress will be saved. In appreciation of your time and input, once you have completed the survey, you will be entered into a draw for one of two $500 cash prizes. We kindly ask that you complete the survey prior to August 22, 2021 by clicking the link below.

Start Survey

To ensure all responses are kept anonymous and confidential, all survey responses will be collected by INNOVATIVE Research Group, an independent market research company. If you would like to verify the authenticity of this survey or would like more information about the survey you can contact marketresearch@enbridge.com.

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Please do not "**Reply**" to this email. This mailbox is not regularly monitored. To stop receiving invitations for our online surveys, please click here to unsubscribe. Your privacy is important to us. For more information please review our Privacy Policy.

Introduction – Telephone Only

[IF RESIDENTIAL CUSTOMER (CUSTOMER=1)]

Hello, my name is ____. I'm calling from Innovative Research Group, a national public opinion research firm. Today, we are conducting a customer survey for Enbridge Gas about your natural gas service as Enbridge Gas develops its investment plans for 2024 and beyond.

I assure you we are not selling anything; we are only interested in your opinions and all of your answers will be kept strictly confidential. This call will take approximately 20 minutes and may be monitored or recorded for quality assurance purposes.

Can I speak with the person in your household who is responsible or jointly responsible for decisions regarding natural gas such as viewing and paying your natural gas bill?

01	Yes – Continue	
02	No – Ask to speak with person	
03	Unavailable – Schedule call back	
97	Do not receive a natural gas bill	**[THANK & TERMINATE]**
98	DK or REFUSE	**[THANK & TERMINATE]**

Thank you. I have some questions to see if you qualify for this study.

[IF COMMERCIAL CUSTOMER (CUSTOMER=2)]

Hello, my name is ____. I'm calling from Innovative Research Group, a national public opinion research firm. Today, we are conducting a customer survey for Enbridge Gas about your natural gas service as Enbridge Gas develops its investment plans for 2024 and beyond.

I assure you we are not selling anything; we are only interested in your opinions and all of your answers will be kept strictly confidential. This call will take approximately 20 minutes and may be monitored or recorded for quality assurance purposes. In appreciation of your time, upon completion of the survey, you will be entered into a draw for one of two $500 cash prizes.

Can I speak with the person in your organization who is responsible or jointly responsible for decisions regarding your natural gas account?

01	Yes – Continue	
02	No – Ask to speak with person	
03	Unavailable – Schedule call back	
97	Do not receive a natural gas bill	**[THANK & TERMINATE]**
98	DK or REFUSE	**[THANK & TERMINATE]**

Thank you. I have some questions to see if you qualify for this study.

A. SCREENER

Screening for qualified respondents

[ONLY ASK A1-A3 IF RESIDENTIAL CUSTOMER (CUSTOMER=1)]

A1. In what year were you born?

	[RANGE 1850-2021]	**[SKIP NEXT QUESTION]**
99	Prefer not to answer	

A2. Which of the following age categories do you fall into?

96	Under 18	**[THANK & TERMINATE]**
01	18 to 24	
02	25 to 44	
03	45 to 64	
04	65 to 74	
05	75 or older	
99	Prefer not to answer	

A3. Do you, or does anyone else in your immediate family work in any of the following areas?

01	Marketing research	**[THANK & TERMINATE]**
02	Energy providers, such as natural gas, oil, electricity, propane	
03	A gas equipment or appliance contractor or retailer	
04	Energy sector regulator or intervener	
97	None of the above	**[MUTUALLY EXCLUSIVE]**

[ONLY ASK A4-A6 IF COMMERCIAL CUSTOMER (CUSTOMER=2)]

A4. To confirm, does your organization receive a natural gas bill from Enbridge Gas?

01	Yes	
02	No	**[THANK & TERMINATE**: Thank you for your interest, but this survey is for customers who receive and pay their natural gas bill]
99	Don't know	

A5. Are you responsible or partially responsible for decisions regarding your natural gas account for your organization?

01	Yes	**[SKIP TO INTRODUCTION]**
02	No	
99	Don't know	

Note: in the online version, the survey terminates if the person selects "no" or "don't know" in A5.

Note: A6 is only asked in the telephone survey.

A6. May I speak to the person who is responsible or partially responsible for decisions regarding your natural gas account for your organization?

01	Yes	
02	No	**[THANK & TERMINATE]**
99	Don't know	**[THANK & TERMINATE]**

And … can I have their …

First Name _____________

Last Name _____________

Title/Position ___________

Phone Number __________

ASK to be transferred …

- **if transferred → go to INTRODUCTION**
- **if not transferred → Thank & Add to Callback List**

B. INTRODUCTION

Enbridge Gas is preparing its business plan to be implemented in 2024 and would like to hear your feedback on a number of things that it is considering in this plan.

Near the end of this survey, you will have the opportunity to provide any additional feedback that you would like to share with Enbridge Gas.

Throughout this survey, if you aren't sure what your response is, please say so. Thank you in advance for your feedback and participation!

C. SATISFACTION

Let's talk about your overall experience with Enbridge Gas.

C7. Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

01	Very satisfied	
02	Somewhat satisfied	
03	Neither satisfied nor dissatisfied	
04	Somewhat dissatisfied	
05	Very dissatisfied	
99	I Don't know	

[ASK C8 IF CUSTOMER=2 (COMMERCIAL) AND 03, 04 OR 05 AT C7]

C8. Is there anything in particular Enbridge Gas can do to improve their service?
[OPEN-ENDED]

D. CUSTOMER OUTCOMES

In considering its business plan to be implemented starting in 2024, Enbridge Gas must make many decisions. We would like your feedback on the outcomes you would like Enbridge Gas to focus on in its plan. Outcomes are the goals and priorities that matter to you.

There is a list of broad outcomes that Enbridge Gas will need to consider. Using a scale from 0 to 10, where 0 means "not at all important" and 10 means "extremely important", please tell us how important each one is to you. Be sure to save a rating of 10 for those items that are most important to you. (IF NECESSARY: If you don't know just say so.) How about… (read list) (Repeat scale as necessary)

[RANDOMIZE]
D9. Reliably delivering natural gas
D10. Safely delivering natural gas
D11. Making good use of the money customers pay
D12. Providing affordable pricing
D13. Providing predictable pricing
D14. Providing dependable customer service
D15. Minimizing any impacts on the environment
D16. Being socially responsible
D17. Supporting the growth of Ontario's economy

00	Not at all important	
01-09		
10	Extremely important	
99	Don't know	

D18. Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which one would you say is most important to you as a customer? If you don't know, just say so.

[USE THE SAME RANDOMIZATION ORDER AT D9-D17]

01	Reliably delivering natural gas	
02	Safely delivering natural gas	
03	Making good use of the money customers pay	
04	Providing affordable pricing	
05	Providing predictable pricing	
06	Providing dependable customer service	
07	Minimizing any impacts on the environment	
08	Being socially responsible	
09	Supporting the growth of Ontario's economy	
99	Don't know	**[SKIP TO NEXT SECTION]**

D19. And which one is second most important to you?
[INSERT LIST, REMOVE ITEM SELECTED AT D18]

D20. And, finally, which one is third most important to you?
[INSERT LIST, REMOVE ITEM SELECTED AT D18 and D19]

E. ASSET MANAGEMENT

Thinking about the level of safety, reliability, and customer service you receive from Enbridge Gas would you like to see the company invest in maintaining or invest in improving upon the current level? How about [INSERT ITEM]? Should Enbridge Gas [INSERT RESPONSE OPTIONS]?

01	Invest in maintaining the current level	
02	Invest in improving the current level	
99	Don't know	

[RANDOMIZE E21-E23]

E21. Safety
E22. Reliability
E23. Customer service

E24. Thinking generally about Enbridge Gas' budget for replacing pipelines and equipment that deliver gas to your **[home/organization]**, which of the following statements best represents your point of view?

[RANDOMIZE 01 AND 02]

01	Enbridge Gas should look at the long-term health of the system and spread costs out evenly over time even if that means higher rates now
02	Enbridge Gas should focus on the immediate impact on rates and only spend what it takes to keep the system in good order now to keep rates low, even if that means an increase in rates later that may end up being more expensive for customers overall
98	I don't have an opinion on this
99	Don't know

F. RATES

Note: F25 and F26, F27 and their preambles were only asked in the online survey.

Enbridge Gas is the only distributor of natural gas service in your area and there is not a competitive market in which rates are determined. For this reason, the Ontario Energy Board (OEB) reviews and approves all Enbridge Gas costs (that is, the costs to operate), and also reviews and approves how customer rates should be calculated.

Enbridge Gas incurs two types of costs in delivering natural gas to your **[home/organization]**, those that are variable and those that are fixed.

One of these is the cost of the natural gas that customers use. This cost is determined by the market and will be passed on to you based on your measured consumption of natural gas.

The fixed costs that Enbridge Gas incurs can be divided into two groups.

[RANDOMIZE PREAMBLE AND F25 WITH PREAMBLE AND F26]

One type of fixed cost is that of being connected to the network. This includes the cost of the pipeline, the pressure regulator, the natural gas meter, meter reading, billing, the contact centre and operations support. These costs are fixed for Enbridge Gas, and are similar for each customer and do not change based on the size of the customer.

F25. How do you feel **[residential/business]** customers like you should be billed for these costs of being connected to the network?

[RANDOMIZE 01 AND 02]

01	Each customer should pay a portion based on the amount of natural gas they use
02	The cost should be paid equally by customers of the same type (i.e. residential or business)
98	I don't have an opinion on this
99	Don't know

One type of fixed cost is that of the network capacity. This includes the cost of the network infrastructure, its operation, maintenance, and natural gas storage to meet the peak demand of customers on the coldest days of the year. These costs are fixed for Enbridge Gas, but may vary for each customer based on their individual level of peak demand.

F26. How do you feel **[residential/business]** customers like you should be billed for these costs of accessing network capacity?

[RANDOMIZE 01 AND 02]

01	Each customer should pay a portion based on the amount of natural gas they use on the coldest days of the year
02	The cost should be paid equally by customers of the same type (i.e. residential or business)
98	I don't have an opinion on this
99	Don't know

[IF RESIDENTIAL CUSTOMER (CUSTOMER=1)]

Enbridge Gas, today, is a combination of Legacy Union Gas and Legacy Enbridge Gas Distribution. Currently there are three rate zones which result in customers paying different rates depending on where you are located in the province and which company you were served by prior to the merger. Enbridge Gas is considering the option of offering one rate zone for its different types of customers, regardless of location within Ontario. There are many benefits of one rate zone including similar charges for similar customers, a consistent customer experience, and reduced administrative costs.

One rate zone could result in a change to the amount you pay today for your natural gas service. Approximately 60% of customers will see very little change to the amount they pay today. Approximately 30% of customers will see an increase of roughly 5% (or roughly $5 per month). Approximately 10% of customers will see a decrease of roughly 10% (or roughly $10 per month).

F27. Considering this, which of the following is closest to your view?
[RANDOMIZE 01 AND 02]

01	Enbridge Gas should implement a single rate zone and make the rates for natural gas service the same across Ontario
02	Enbridge Gas should leave the rate zones as they are where customers pay different rates for natural gas service based on where they live
98	I don’t have an opinion on this
99	Don’t know

Note: F28 was asked in the telephone and online versions of the survey.

[IF COMMERCIAL CUSTOMER (CUSTOMER=2)]

Enbridge Gas, today, is a combination of Legacy Union Gas and Legacy Enbridge Gas Distribution. Currently there are three rate zones which result in customers paying different rates depending on where you are located in the province and which company you were served by prior to the merger. Enbridge Gas is considering the option of offering one rate zone for its different types of customers, regardless of location within Ontario. There are many benefits of one rate zone including similar charges for similar customers, a consistent customer experience, and reduced administrative costs.

One rate zone could result in a change to the amount you pay today for your natural gas service. The impact is dependent on the amount of natural gas you use but could range from +5% to -10% of the amount you pay today.

F28. Considering this, which of the following is closest to your view? If you don’t have an opinion or are not sure, please say so.

01	Enbridge Gas should implement a single rate zone and make the rates for natural gas service the same across Ontario

02	Enbridge Gas should leave the rate zones as they are where customers pay different rates for natural gas service based on where they live
98	I don't have an opinion on this
99	Don't know

G. Customer Care

G29. When you consider options for paying your bill, how important is it to you that Enbridge Gas provides customers the option to pay their bills by credit card?

01	Very important	
02	Somewhat important	
03	Not very important	
04	Not at all important	
99	Don't know	

G30. Credit card companies charge Enbridge Gas a fee for any payments that customers make by credit card. Do you believe that the costs of those credit card charges should be spread out among all customers, or should customers who choose to pay by credit card pay for these charges? If you don't have an opinion on this question or are not sure just say so.

[ROTATE 01 AND 02]

01	Spread out among all customers	
02	Paid by the customer choosing to pay by credit card	
98	I don't have an opinion on this	
99	Don't know	

[ASK G31 IF CUSTOMER=2 (COMMERCIAL)]

G31. One of the tools that Enbridge Gas offers customers is a customer service team that can respond to phone calls or emails. How important is it to you that business customers like you have a dedicated team to respond to business customers specifically?

01	Very important	
02	Somewhat important	
03	Not very important	
04	Not at all important	
99	Don't know	

H. New or Harmonized Programs and Policies

Note: H32, H33 and H34 and their corresponding preambles were only asked in the online survey.

Cross Bore

While rare, it is possible that a natural gas line may intersect with a sewer line. When this happens, it is called a utility cross bore. This is unintentionally created when a natural gas line is installed through a process of trenchless drilling. Trenchless drilling is used to avoid creating open trenches that can disturb roads, driveways, and gardens, but it relies on locates of existing utilities which may not always be accurate for various reasons. While a utility cross bore may not pose an immediate risk, it may become an issue if a sewer line needs to be cleared in the case of a blockage.

Enbridge Gas intends to implement a program to proactively inspect and resolve any utility cross bores that may have been installed in the past. Also, a program has been implemented to prevent new installations from creating new cross bores even though that will increase the cost of the installation and require additional restoration work.

H32. These programs to proactively inspect and resolve existing cross bores and to prevent the creation of cross bores during the completion of new installations combined would cost customers $0.50 per year for 5 years. Which of the following is closest to your view?

[RANDOMIZE 01 AND 02]

01	Enbridge Gas should implement the proactive program and continue with the preventative program to eliminate existing cross bores and prevent any new cross bores to maintain safety, even though it costs more.
02	Enbridge Gas should leave its processes of trenchless drilling as is and only resolve those that come up as an issue arises, even though this may create additional cross bores which increases safety risk.
98	I don't have an opinion on this
99	Don't know

Infill Policy – RESIDENTIAL CUSTOMERS ONLY

[ASK IF CUSTOMER=1 (RESIDENTIAL)]

When an existing home is located near a main line, it may receive a natural gas connection through the residential infill policy. Under regulations, existing customers cannot be charged for any of these expenses.

According to the policy, connections are provided to homeowners at no cost (because forecasted revenues cover a portion of the cost to connect) up to a certain distance from the home to the main line. The cost for any extra distance must be paid by the homeowner. These costs can be structured in a number of different ways, and currently vary depending on whether someone is in the Legacy Enbridge Gas or Legacy Union Gas area.

H33. Enbridge Gas would like to create a policy that is the same across the entire territory and would like to ask you for your opinion. Thinking about general principles, which of the following approaches is closest to your view?

[RANDOMIZE 01 THROUGH 05]

01	Enbridge Gas should offer a shorter distance of the pipe at no cost, and charge a lower cost per meter for the remaining length to the homeowner
02	Enbridge Gas should offer a longer distance of the pipe at no cost, and charge a higher cost per meter for the remaining length to the homeowner
03	Enbridge Gas should determine a flat rate that would require each homeowner to pay the same amount regardless of the length of the pipeline required
04	Enbridge Gas should offer a cost per meter for the entire length of the pipe
05	Enbridge Gas should develop a full feasibility study for each new attachment, even if this requires additional resources, and charge homeowners the actual cost of the installation
98	I don't have an opinion on this
99	Don't know

Cut off at Main – RESIDENTIAL CUSTOMERS ONLY

[ASK IF CUSTOMER=1 (RESIDENTIAL)]

When a customer wants to cut off the natural gas service, for example, when a home is being demolished, when there has been a fire, or when a customer no longer wishes to receive natural gas service, the service is cut off at the main pipeline. This work is performed by a maintenance and construction crew. After that, in many cases a new home can be attached again at the same location. Not doing this work creates abandoned natural gas lines and meters, which may pose a safety risk.

Any costs not charged to the homeowner are covered by Enbridge Gas, which means all ratepayers contribute to these costs through their rates.

H34. Enbridge Gas would like to create a policy that is the same across the entire territory and would like to ask you for your opinion. Which of the following is closest to your view?

[RANDOMLY FLIP ORDER OF FIRST 3 OPTIONS]

01	Enbridge Gas should charge the homeowner the full cost of the cut off at main.
02	Enbridge Gas should charge a portion of the cost to the homeowner, ensuring that costs are not too prohibitive that natural gas lines are not left in an unsafe condition.
03	Enbridge Gas should not charge the homeowner for these costs of the cut off at main. These costs should be shared among all ratepayers.
98	I don't have an opinion on this
99	Don't know

Automated Meter Infrastructure – ASK ALL

The gas meter technology currently used by Enbridge Gas has not changed in many years. There are new, advanced, meters available that would send the usage information to Enbridge Gas through a wireless network, similar to your electricity or water usage meters.

Please tell me how important each of these features is to you.

01	Very important
02	Somewhat important
03	Not very important
04	Not at all important
99	Don't know

[RANDOMIZE]

H35. Enable Enbridge Gas to remotely and automatically shutoff gas supply if needed in the event of an emergency
H36. Enable Enbridge Gas to better detect and respond to possible gas leaks
H37. Lower GHG emissions by reducing meter reader vehicles on the road
H38. Enable access to more accurate, hourly updates to better understand and manage your natural gas use
H39. Eliminate Enbridge Gas' need to regularly access your property to conduct a meter reading
H40. Eliminate the need for estimated meter reads (where your usage and bill are estimated and adjusted in a following month)

I. ENERGY TRANSITION

Let's look ahead and think about the future.

Thinking about everything you know today, and considering any changes that you might expect in the future as it relates to all the energy choices available to you, how much natural gas do you think someone like you will be using in **(INSERT TIME)**, compared to today? How about in **(INSERT other TIME)**?

01	Significantly less
02	Somewhat less
03	About the same
04	Somewhat more
05	Significantly more
99	Don't know

[DO NOT RANDOMIZE]

I41. 10 years
I42. 30 years

When you consider options and solutions to reduce impacts on the environment, please tell me whether you agree or disagree with the following statements.

01	Completely agree
02	Somewhat agree
03	Neither agree nor disagree
04	Somewhat disagree
05	Completely disagree
99	Don't know

[RANDOMIZE]

I43. Enbridge Gas should actively be investing in low-carbon options and solutions that would help reduce impacts on the environment
I44. Given its experience, Enbridge Gas is well positioned to support the development of low-carbon options and solutions
I45. I look to Enbridge Gas to help develop offerings and new solutions that will help me reduce my natural gas usage

[END BATTERY]

Note: I46, I47, I48 and I49 and their corresponding preambles were only asked in the online survey.

Let's focus on some ways that Enbridge Gas can help minimize any impacts on the environment. Following are descriptions of three potential ways in which Enbridge Gas can minimize the impact of natural gas on the environment.

[RANDOMIZE PREAMBLE+I46, PREAMBLE+I47 AND PREAMBLE+I48]

Reduce demand / avoid new infrastructure (IRP)

When considering new or expanded pipeline projects, Enbridge Gas is required to evaluate whether alternatives are available that would eliminate the need for the project altogether. This would mean looking for ways to help customers reduce the amount of natural gas they use through conservation programs or other options. Examples could include incentives for installing new windows and doors, adding insulation, or upgrading your furnace or water heater. It could also include delivering compressed natural gas by truck or train to locations where pipelines do not exist. Other alternatives that reduce the need for natural gas might include geothermal heating and cooling, or air source heat pumps.

I46. How much, if anything, would you be willing to pay per year for Enbridge Gas to develop solutions in natural gas conservation and other non-pipeline alternatives instead of new pipeline or capacity projects?

[RANDOMIZE SCALE IN ASCENDING VS DESCENDING ORDER]

Residential response choices are in blue

Commercial response choices are in red

01	$1.00/month or $12.00 extra per year / 2% added to the delivery portion of your bill
02	$2.00/month or $24.00 extra per year / 4% added to the delivery portion of your bill
03	$4.00/month or $48.00 extra per year / 8% added to the delivery portion of your bill
04	$10.00/month or $120.00 extra per year / 10% added to the delivery portion of your bill
88	Some other amount per month [ON-SCREEN INSTRUCTION: [RES] Please enter a numeric response in the space below. You may use a decimal point, but do not include a dollar sign. [BUS] Please enter a numeric response in the space below. Do not include the % sign.]
97	I would not be willing to pay anything extra
99	Don't know

Low-carbon options / greening the gas

Other options Enbridge Gas may invest in that focus on reducing the amount of greenhouse gas emissions can include options that "green the gas." An example of this would be blending traditional natural gas with greener sources of gas, such as renewable natural gas derived from organic waste from farms, landfills, and water treatment plants, or hydrogen gas derived from using surplus electrical energy that is converted to hydrogen gas through electrolysis technology.

I47. How much, if anything, would you be willing to pay per year for Enbridge Gas to develop solutions in greening the gas to reduce the greenhouse gas emissions from the use of natural gas?

[RANDOMIZE SCALE IN ASCENDING VS DESCENDING ORDER]

01	$1.00/month or $12.00 extra per year / 2% added to the delivery portion of your bill
02	$2.00/month or $24.00 extra per year / 4% added to the delivery portion of your bill
03	$4.00/month or $48.00 extra per year / 8% added to the delivery portion of your bill
04	$10.00/month or $120.00 extra per year / 10% added to the delivery portion of your bill
88	Some other amount per month [ON-SCREEN INSTRUCTION: [RES] Please enter a numeric response in the space below. You may use a decimal point, but do not include a dollar sign. [BUS] Please enter a numeric response in the space below. Do not include the % sign.]
97	I would not be willing to pay anything extra
99	Don't know

New Technologies

Enbridge Gas can also support the advancement of various new low-carbon or energy efficient technologies that may not exist today. This would include participating in new research, development and supporting various pilot projects.

I48. How much, if anything, would you be willing to pay per year for Enbridge Gas to develop solutions in developing and advancing new low-carbon and energy efficient technologies?

[RANDOMIZE SCALE IN ASCENDING VS DESCENDING ORDER]

01	$1.00/month or $12.00 extra per year / 2% added to the delivery portion of your bill
02	$2.00/month or $24.00 extra per year / 4% added to the delivery portion of your bill
03	$4.00/month or $48.00 extra per year / 8% added to the delivery portion of your bill
04	$10.00/month or $120.00 extra per year / 10% added to the delivery portion of your bill
88	Some other amount per month [ON-SCREEN INSTRUCTION: [RES] Please enter a numeric response in the space below. You may use a decimal point, but do not include a dollar sign. [BUS] Please enter a numeric response in the space below. Do not include the % sign.]
97	I would not be willing to pay anything extra
99	Don't know

Certified natural gas

Enbridge Gas is looking at options to ensure that the natural gas it purchases is responsibly sourced. This means the companies who produce the natural gas adhere to higher standards than the minimum government standards. This relates to areas such as minimizing impacts to air and water quality, lowering carbon emissions during production, and stronger engagement with Indigenous communities, etc. While it may not always cost more, it is possible that this responsibly sourced natural gas comes at a small premium and would cost customers a little bit more.

I49. Considering this, would you support Enbridge Gas sourcing this type of natural gas to deliver to you, even if it comes at a small premium?

01	Definitely support
02	Somewhat support
03	Neither support nor oppose
04	Somewhat oppose
05	Definitely oppose
99	Don’t know

J. ADDITIONAL COMMENTS

J50. Is there anything that you would like to share with Enbridge Gas as it works on building its investment plan for the future?

[OPEN-ENDED]

K. RESIDENTIAL DEMOGRAPHICS

[ASK SECTION L ONLY IF CUSTOMER=1 (RESIDENTIAL)]

These last few questions are for statistical purposes only, and all of your responses are confidential.

K51. Including yourself, how many people in total live in your household?

	[RANGE 1 TO 100]
99	Prefer not to answer

K52. Which of the following best describes your total annual household income (after taxes)? *Please stop me when I get to your response… **READ LIST***

01	$28,000 or less	**[COMBINE WITH K51 TO DETERMINE LEAP QUALIFICATION]**
02	Between $28,001 and $39,000	
03	Between $39,001 and $48,000	
04	Between $48,001 and $52,000	
05	Between $52,001 and $72,000	
06	Between $72,000 and $81,300	
07	Between $81,301 and $90,500	
08	Over $90,500	
99	Prefer not to answer	

L. FIRMOGRAPHICS

[ASK ONLY IF CUSTOMER=2 (COMMERCIAL)]

L53. Approximately how many employees, including yourself, does your company presently employ at this location?

[RANGE 1-999999]

99	Don't know

L54. How do you use natural gas at your organization? Please check as many as apply.

01	Natural gas is used in production process
02	Natural gas is used as feedstock
03	Natural gas is used for heating or space conditioning
04	Natural gas is used for water heating
88	Other
99	Don't know

M. THE END

Those are all the questions we have for you. It is greatly appreciated and very helpful that you took the time to help us serve you better. On behalf of Enbridge Gas, thank you.

[ASK ONLY IF CUSTOMER=2 (COMMERCIAL)]

In order to make sure we are entering the correct person in the prize draw, may I please get your full name and mailing address?

FIRST NAME
LAST NAME
STREET ADDRESS
CITY
POSTAL CODE
PHONE NUMBER
[PROVIDE OPTION TO REFUSE INCENTIVE]

Customer Engagement

Phase III: Workbook

GS (Residential) Workbook

December 2021

About this Customer Engagement

Welcome to the Enbridge Gas Customer Engagement!

As Enbridge Gas plans for the future, it needs your input into choices that will impact the services you receive and the rates you pay.

- Enbridge Gas is looking for your feedback on its draft investment plan for 2024 and beyond to ensure that the plan reflects your needs and preferences.
- You don't need to be a natural gas expert to complete this workbook. It focuses on basic choices between outcomes that matter to you and provides the background information you need to answer the questions.
- The most important part of this workbook are the survey questions. While your view may not always align exactly with any of the options presented, please select the one that is closest. If you truly aren't sure, select the "don't know" option.

This workbook will take approximately 20-30 minutes to complete. Your progress will be saved as you move through the workbook, meaning you can leave and return to complete it at any time.

Those who complete the questions that follow will be invited to enter a draw to win one of four $250 cash prizes.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

If you are reading this on a smaller mobile device, you may wish to access the survey from a tablet, desktop or laptop instead, so that it is easier to read.

Background

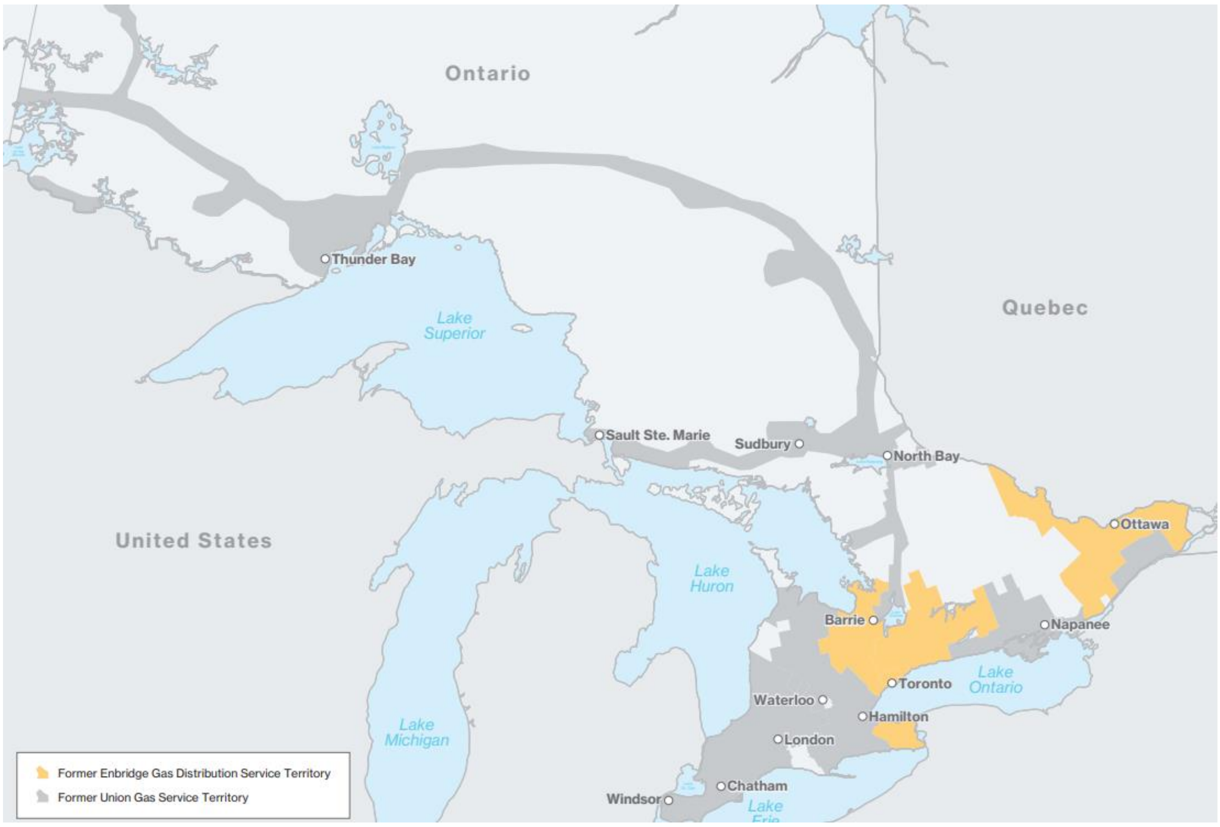
Who is Enbridge Gas?

Enbridge Gas Inc. is based in Ontario and delivers energy to customers in Ontario. Its parent company Enbridge Inc. is headquartered in Calgary, Canada, and operates across North America. Rates and business plans developed by Enbridge Gas must be approved by the Ontario Energy Board (the OEB), which regulates natural gas utilities in Ontario.

Enbridge Gas …

- ✓ Distributes natural gas to about 3.8 million residential, business and industrial customers
- ✓ Attaches more than 50,000 new customers each year
- ✓ Has agreements to provide gas distribution service within 313 municipalities and provides natural gas within 23 First Nations communities
- ✓ Has a network of over 151,500 kilometers of underground pipeline

In 2019, Enbridge Gas Distribution and Union Gas merged to form one company, Enbridge Gas Inc. Throughout this workbook we occasionally refer to Legacy Enbridge Gas Distribution and Legacy Union Gas (the previous companies), but mainly refer to the whole service area or territory that Enbridge Gas serves today.



Background

Where do your rates go?

Below is an example of a residential natural gas bill.

The charges outlined in Orange are the costs of getting the gas to you once it reaches the Enbridge Gas system. At times, this may require a Rate Adjustment which, along with other rates, is determined through a regulatory process.

CHARGES FOR NATURAL GAS

May 12, 2021 - Jun 10, 2021

Customer Charge	$21.83
Delivery to You	$6.17
Transportation to Enbridge	$2.39
Federal Carbon Charge	$4.62
Gas Supply Charge	$7.05
Cost Adjustment	$0.71 CR
Charges for Natural Gas	**$41.35**
HST*	$5.37
Total Charges for Natural Gas	**$46.72**

OTHER ENBRIDGE CHARGES

Rate Adjustment	$5.24 +HST
HST*	$0.68
Total Other Enbridge Charges	**$5.92**

The charges outlined in Blue are the 'passed through' costs that pay for the natural gas you use (Gas Supply Charge and Cost Adjustment) and the cost of transporting it from where it is produced to the Enbridge Gas system (Transportation to Enbridge). If customers buy their natural gas through an energy marketer these costs would be subject to the agreement with the energy marketer.

Enbridge Gas is also responsible for collecting HST and the Federal Carbon Charge on behalf of the government. While some of these costs may be given back to customers in rebates, how these funds are used is determined by the government and is out of Enbridge Gas' control.

The average residential customer consumes approximately 2,400m3 of natural gas per year.

The pie chart below shows where the money goes.

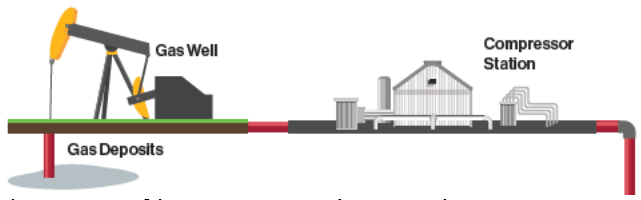
The Blue slice shows the 'passed through' costs that pay for the natural gas and transportation to the Enbridge Gas system.

The money that goes to Enbridge Gas is in the other two slices.

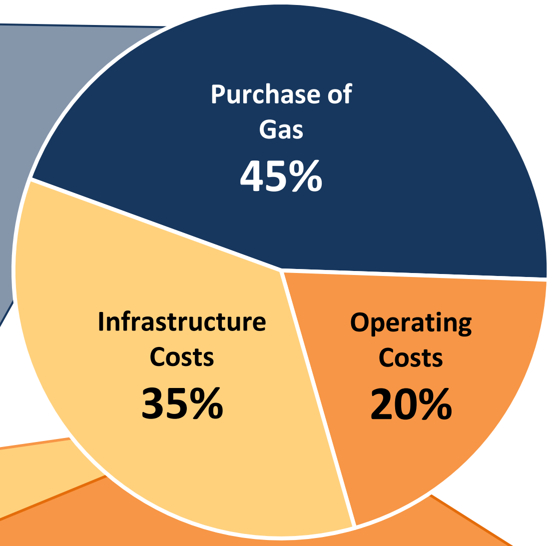
- The Light Orange slice pays the capital costs of the infrastructure (such as pipes, compressors, buildings and other equipment) used to move and store natural gas across the system.
- The Dark Orange slice pays for operations – including the people who operate and maintain the equipment and the people who answer your calls and provide customer service.

Connect to next page in the online version. All on one page there.

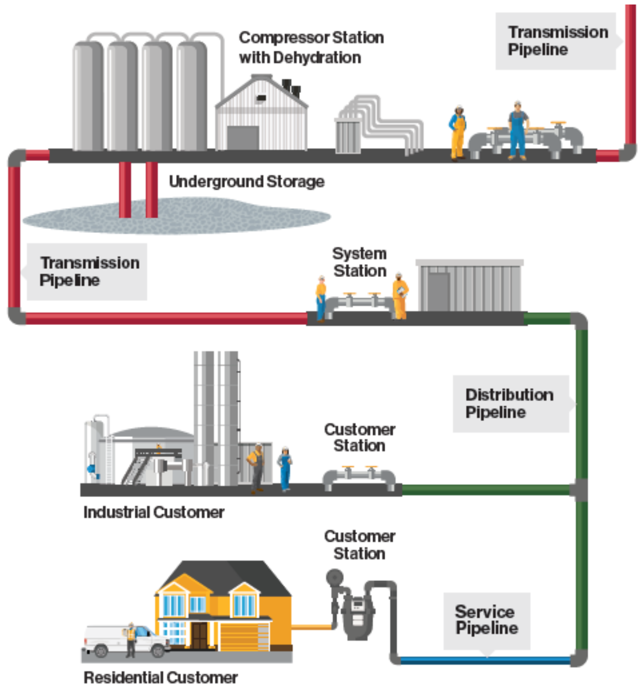
Purchase of Gas



The costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board, and are passed on to customers at cost.



Infrastructure



Once gas reaches the Enbridge Gas system, it is metered and then delivered to customers through a distribution system of local gas mains, small-diameter service lines and, ultimately, customer meters.

Natural gas is often stored in large underground reservoirs to help meet spikes in demand, particularly in winter.

Operations

Delivering gas to customers is just one part of Enbridge Gas' activities. Enbridge Gas provides a variety of supporting services to customers including:

- Manage and operate its call centres, ombudsperson offices, and its online My Account system to help customers manage their account online.
- Complete meter replacements, inspections, and respond to emergency calls.
- Conduct millions of meter readings each year.
- Offer programs to help customers reduce their natural gas usage. Since 1995, Enbridge Gas has saved its customers 30 billion lifetime cubic meters of natural gas and 56.2 million tonnes of greenhouse gas emissions, the equivalent of taking 12.2 million cars off the road for a year or heating 13.1 million natural gas homes for a year. These programs get approved by the Ontario Energy Board in a separate process and the costs for these programs are included in your rates.

Before this survey, how familiar were you with Enbridge Gas when it comes to delivering natural gas to homes and businesses in Ontario?

- ☐ Very familiar and could explain the details of the Enbridge Gas system to others
- ☐ Somewhat familiar with the Enbridge Gas system but could not explain the details to others
- ☐ Had heard of some of the terms mentioned, but knew very little about the Enbridge Gas system
- ☐ I knew nothing about the Enbridge Gas system
- ☐ Don't know

Where does this consultation fit?

Here in Ontario, customer views are central to the utility planning process.

- **Rates and business plans must be approved by the Ontario Energy Board (the OEB).**
- **The OEB requires that utilities consult with customers to understand your views on key trade-offs.**
- **In addition, the utilities must show how they took customer views into account when developing the plan.**

While some planning decisions will depend on detailed knowledge of engineering and industry standards, in other cases the choices will involve trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down. That is where you come in.

The diagram below shows how customers play a role at three points as Enbridge Gas develops and submits its business plan to the OEB.

How does Customer Engagement Impact Business Planning?

Enbridge Gas has developed a phased approach to gathering and responding to customer feedback.

✓ **1. Identify Customer Priorities**
In June through August of 2021, Enbridge Gas asked residential and business customers about their priorities for natural gas service.

✓ **2. Use Customer Feedback to Guide Development of Plan**
Enbridge Gas planners were given summaries of the key findings from the initial customer engagement to consider as they began building their plans.

You are here

3. Collect Customer Feedback on the Draft Plan
Now Enbridge Gas is returning to customers to get feedback on the draft plan and ask customers how the plan fits with their needs and preferences.

4. Re-Examine Plan
Enbridge Gas has an opportunity to make appropriate changes to the plan based on customer feedback.

5. Submit the Plan to the Ontario Energy Board (OEB)
Enbridge Gas will file the plan, with this workbook, and a summary report with the OEB, where it will be examined by the OEB, consumer advocates and other independent parties in a public hearing. **Customers** can view and comment on this application through the OEB website.

How well do you feel you understand how your feedback fits within the planning process?

☐ Very well ☐ Somewhat well ☐ Not very well ☐ Not at all ☐ Don't know

Customer Experience

Satisfaction and Areas of Improvement

Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don’t know

Is there anything in particular Enbridge Gas can do to improve their service to you? [OPEN]

How do you know if Enbridge Gas is doing a good job for you, or not? [OPEN]

Background

2024-2028 Plan

Plan Objectives

The Enbridge Gas business plan focuses on many of the same objectives as in the past years, as well as future challenges and pressures. Some of the high-level objectives of the plan are as follows:

1. **Maintain system safety and reliability** – ensure that the system continues to operate safely and reliably.

2. **Contain costs** – the OEB requires all utilities to "demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives".

3. **Harmonize rates and services** – ensure that the offerings are consistent across the entire service area as Enbridge Gas continues its merger activities.

4. **Prepare for the future** – ensure that the system is ready for low-carbon options, as well as offer options to help customers reduce their greenhouse gas (GHG) emissions.

Climate Change Goals

Compared to the past, Enbridge Gas' 2024-2028 plan places more emphasis on preparing for the future. Enbridge Gas is looking at ways in which it can support its organizational, as well as federal and provincial goals to reduce GHG emissions and achieve net zero targets.

- **Enbridge Inc. targets to reduce, from its operations, GHG emission intensity by 35% by 2030 over 2018 levels, and to reach Net Zero GHG emissions by 2050**
- **Federal targets to reduce GHG emissions by 40-45% by 2030 over 2005 levels and to reach Net Zero GHG emissions by 2050**
- **Provincial target to reduce GHG emissions by 30% by 2030 over 2005 levels**

How We Can Reduce GHG Emissions From Natural Gas

One of the ways in which GHG emissions are created is through the burning of fossil fuels such as coal, oil, and natural gas. Two key approaches can reduce the emissions from using natural gas:

- by blending lower carbon fuels into the gas supply, including Renewable Natural Gas (RNG) and Hydrogen gas, and
- by improving energy efficiency of homes and businesses, and implementing new, lower-emitting technologies.

Each of these could introduce new, higher, costs that would be passed on to customers but would mitigate costs that might be required to introduce other programs or options to reduce overall GHG emissions in Ontario and Canada. **Later in the workbook we will ask about your views on these potential costs.**

Do these objectives seem like the right approach or the wrong approach?
☐ Right approach ☐Wrong approach ☐ Don't know

Is there anything you would change about this approach or any other comments you would like to make?
Comments:

Calculating Rates

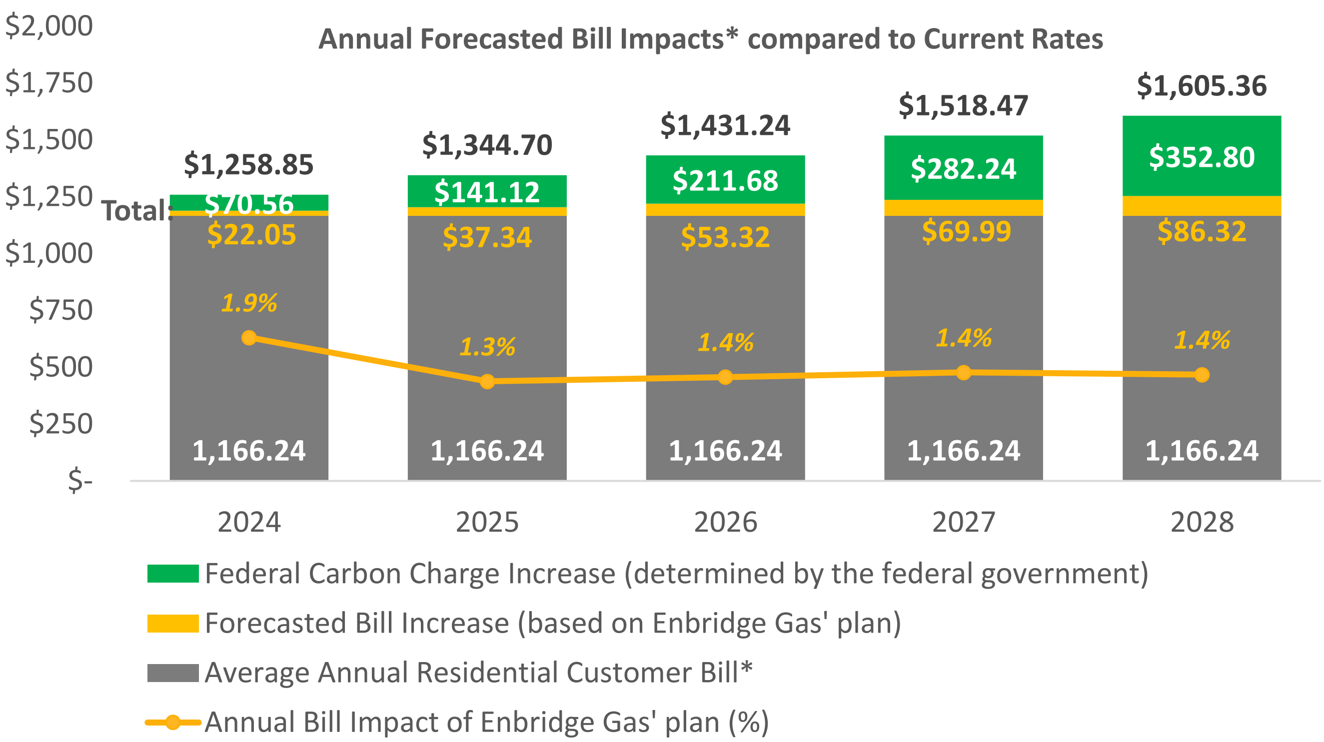
When looking at its overall objectives, and its budgets, there are many items that Enbridge Gas must consider that affect its costs, and in turn the rates that customers pay. Some of these items are determined by regulatory requirements, others by external factors in the market, and again others by decisions made by Enbridge Gas.

There are **accounting policies and factors** that affect expenditures. These include proposals through which Enbridge Gas manages business risk and how it calculates the depreciation of its assets. These types of proposals contribute significantly to the overall rate impact shown in the "Forecasted Bill Increase" below, and are partially offset by savings in other areas. While these issues are too technical for this workbook, they will be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Operating expenses make up about 20% of Enbridge Gas' overall expenditures. Current estimates show that these expenses would increase somewhat over the 2024-2028 period, with the highest annual increase at 1.5%, which is less than inflation. Decisions on operating expenses are based on industry best practices and generally do not involve trade-offs between customer outcomes. Since these are technical issues, they will also be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Capital expenses make up about 35% of Enbridge Gas' overall expenditures and pay for investments in its equipment that have lasting benefits over many years. Since capital spending includes major one-off projects as well as ongoing maintenance and replacement, capital spending varies from year to year. The questions in the next section focus on these choices.

The *Forecasted Bill Impacts* for the 2024 to 2028 compared to current rates are shown below. Compared to your current rates, rates in 2022 are expected to increase by $8.98 or 0.8% for the average customer, while 2023 rates are not yet established.



**These estimates are preliminary and are subject to both your feedback and ongoing work to review as Enbridge Gas planners continue to work on their plans. This does not include any potential changes in the fuel costs or the federal carbon charge.*
Based on the average customer consuming 2,400 m3 of natural gas per year. Oct 2021 average includes the federal carbon charge.

How well do you feel you understand the projected increase in your rates from 2024 to 2028?
☐ Very well ☐ Somewhat well ☐ Not very well ☐ Not at all ☐ Don't know

Making Choices

In this next section of the workbook, we will ask you about some of the key items that Enbridge Gas is considering in its plan that see trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down.

Some of these items are currently included in the draft budget, while others will need to be added to the budget depending on further analysis and feedback from customers like you.

For each question, where applicable, the financial impact is expressed as the dollar impact each year on an average residential bill. The actual impact will depend on your own individual usage.

At the end of the section, you will have an opportunity to review your responses and their impact on your bill. You will then be able to adjust your choices to provide what you feel is the best balance.

Compression Stations

Enbridge Gas has 50 Compressors, 7 Dehydrators and supporting equipment. These are required to ensure that the gas that is injected into storage or into the distribution system meets the quality specifications and to move gas along the transmission system.

As compressors age, they experience breakdowns on an increasingly frequent basis – when equipment manufacturers stop supporting these compressors, the time to complete repairs can be extensive leading to reliability and gas quality problems. There are two compressors that will need to be replaced in the coming years.

When considering a project to replace compressors like this, Enbridge Gas looks at various options:

- ✓ Replacing one larger compressor with two smaller ones,
- ✓ Using alternative fuel sources such as electricity or hydrogen gas, and
- ✓ Preparing for outages by having spare parts available.

In this case, however, there is a lack of viable alternatives at the specific locations for the two compressor stations, so Enbridge Gas is planning to replace one compressor station in 2026, with the other one being replaced after 2028 to use the existing stations for as long as possible.

Not doing this work increases the risk the station could fail. This may require Enbridge Gas to buy more gas on the market (if available), rather than drawing gas from its storage. This introduces the risk of price volatility, as gas purchased on the market during the coldest days of the year has been up to 220% more expensive in the past 5 years than the gas that could be drawn from storage.

Image: inside a building housing a compressor station

Furthermore, if the station fails, replacement will still be required which would take a couple of years of construction to complete, extending the risks for longer. The replacement of the first compressor station is planned for 2026 and would cost the average customer $2.43/year. Which of the following statements best represents your point of view?

[RANDOMIZE 01 and 02]

Connect to next page in the online version. All on one page there.

01	Enbridge Gas should replace the compressor stations as it currently plans, replacing one compressor station during the period of its 2024-2028 plan, at a cost of $2.43/year.
02	Enbridge Gas should defer the compressor station project for as long as possible, even though this carries with it increasing risk of outages and with that, greater price volatility. The cost of this is subject to market prices at the time.
98	I don't have an opinion on this
99	Don't know

Comments:

Making Choices

Vintage Steel Pipeline Replacement Program

Enbridge Gas has implemented a Vintage Steel Pipeline Replacement Program, which focuses on replacing older steel pipelines within the system. It is considering ramping up the program to ensure ongoing safety and reliability of the distribution system and to prepare the network for the eventual delivery of low carbon, blended hydrogen. Blended hydrogen can safely be delivered through modern steel and plastic distribution systems – however, with the rapid introduction of natural gas to Ontario during the 1950's and 60's, Enbridge Gas has a lot of older steel pipelines which are nearing end of life and require replacement in a planned and proactive manner.

This program would see an increase in work and a ramp-up of spending starting in 2024 with the goal of replacing 5,100 km of 17,000 km of vintage steel pipelines in 20 years. These vintage steel pipelines were built before 1971 and are more prone to failures compared to steel pipelines built later due to materials, construction and damage prevention practices used at the time. Using risk assessments, the program will focus on replacing pipelines that are closest to end of life first.

Enbridge Gas intends to start this increase in work in 2024 so that the work can be spread out over a longer period with a limited increase to internal resources. Pushing the work into the future, such as 10 years from now, to achieve the same objectives, will require additional internal as well as external resource overheads and costs, with reduced productivity due to a sharper ramp-up of skilled labour. The overall costs would be expected to be higher with a delayed approach.

It is estimated that this program, ramping up in 2024, included in the capital budget, is equivalent to an average annual increase of $1.22/year from $0.81 increasing to a total of $6.10 in 2028 for the average customer.

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 and 02]

01	Enbridge Gas should increase its spending on the Vintage Steel Replacement Program in order to help prepare the system for the future by starting to ramp-up the work in 2024 at an average annual increase of $1.22/year from $0.81 increasing to a total of $6.10 in 2028.
02	Enbridge Gas should defer proactive replacement of its system that would prepare it for the future – even if this means that the cost will be higher in the future.
98	I don't have an opinion on this
99	Don't know

Comments:

Making Choices

Hydrogen Gas

Enbridge Gas is looking at options to blend more Hydrogen gas into the natural gas it delivers to green the gas supply.

Clean hydrogen gas is derived from surplus clean electrical energy that is converted to hydrogen gas through electrolysis technology. The gas is then blended with traditional natural gas, reducing GHG emissions.

Enbridge Gas is considering investing more in clean hydrogen as a tool for reducing GHG emissions in Ontario to allow for additional hydrogen gas to be blended into the natural gas distribution system. This would mean expanding the pilot project at the power-to-gas (P2G) facility in Markham where hydrogen gas is currently being produced, to deliver hydrogen-blended natural gas to a larger network of customers, expanding the blended gas area from approximately 3,600 to just under 17,000 customers.

Image: Hydrogen gas can be stored in tanks

Additionally, Enbridge Gas intends to launch a feasibility study that assesses the full system's readiness for more hydrogen gas to be included in the system. The costs for these projects for the average residential customer are estimated as follows:

	2024	2025 and 2026	2027 and 2028
Annual cost	$0.37	$0.47	$0.24

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 and 02]

01	Enbridge Gas should implement these plans for hydrogen gas, which will cost the average residential customer $0.37 in 2024, increasing to $0.47 in 2025 and 2026 and $0.24 in 2027 and 2028, including the cost of the hydrogen gas.
02	Enbridge Gas should not implement these plans related to Hydrogen gas to reduce GHG emissions and keep rates as low as possible
98	I don't have an opinion on this
99	Don't know

Comments:

Making Choices

Innovation and Technology Fund

Enbridge Gas can support the advancement of various new low-carbon or energy efficient technologies that may not be available to consumers today.

While some of this work is already taking place on a small scale, the budget for these types of projects is currently very limited. Additional contributions from customers would allow Enbridge Gas to expand this type of research and development work.

Similar to other jurisdictions, Enbridge Gas is considering an **Innovation and Technology Fund** in order to support the research, development, and the bringing to market of new low-carbon or energy efficient technologies. Where possible, this would be in partnership with other utilities and organizations.

Some options include funding for …

- new research on energy efficiency technologies,
- hydrogen gas,
- renewable natural gas, or
- carbon capture, utilization and sequestration (CCUS). This is the process of capturing carbon dioxide before it enters the atmosphere and either use it as a resource to create products or permanently storing it underground.

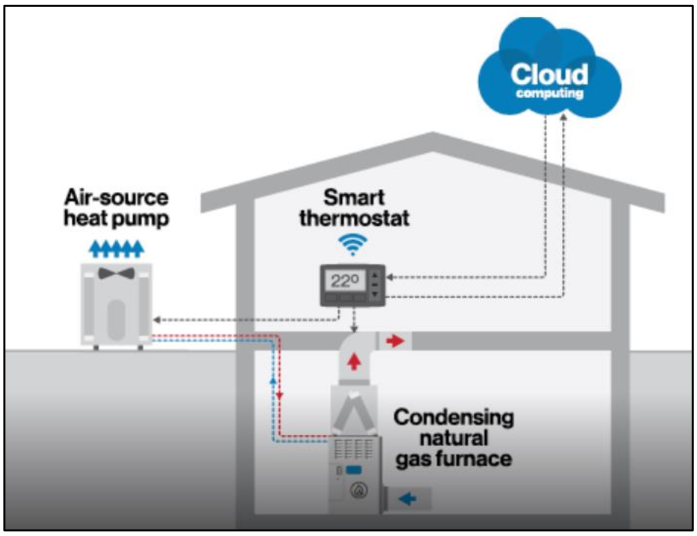


Image: Ontario pilot program tests future of advanced hybrid heating

The more money in this fund, the more projects could be completed, however Enbridge Gas is committed to finding a right balance of spending and planning for the future.

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 THROUGH 03 AND 03 THROUGH 01]

01	Enbridge Gas should develop this fund, spending $1M/year which would cost the average customer $0.26/year
02	Enbridge Gas should develop this fund, spending $5M/year which would cost the average customer $1.28/year
03	Enbridge Gas should develop this fund, spending $10M/year which would cost the average customer $2.56/year
04	Enbridge Gas should **not** develop a fund to invest in new low-carbon or energy efficient technologies
98	I don’t have an opinion on this
99	Don’t know

Comments:

Making Choices

Cut off at Main

When a customer wants to cut off the natural gas service, for example, when a home is being demolished, or when a customer no longer wishes to receive natural gas service, the service is cut off at the main pipeline. This customer requested work is performed by a maintenance and construction crew. After that, in many cases a new home can be attached again at the same location. Not doing this work creates abandoned natural gas lines and meters, which may pose a safety risk.

Any costs not charged to the homeowner are covered by Enbridge Gas, which means all ratepayers contribute to these costs through their rates. The average number of cutoffs in a year are projected at 3,200.

Enbridge Gas would like to create a policy that is the same across the entire territory and would like to ask you for your opinion. Which of the following is closest to your view?

[RANDOMIZE 01 THROUGH 03 AND 03 THROUGH 01]

01	Enbridge Gas should charge the homeowner the full cost of the cut off at main. Average cost for a cut off at main is approximately $3,700.
02	Enbridge Gas should charge the homeowner $750, and the remainder would be shared among all residential customers at an annual cost of $0.25 in 2024 increasing to $1.23 in 2028 for all projected cut-offs.
03	Enbridge Gas should not charge the homeowner for these costs of the cut off at main. These costs should be shared among all residential customers at an annual cost of $0.30 in 2024 increasing to $1.52 in 2028 for all projected cut-offs.
98	I don’t have an opinion on this
99	Don’t know

Comments:

Making Choices

Cross Bores

While rare, it is possible that a natural gas line may intersect with a sewer line. When this happens, it is called a utility cross bore. This is unintentionally created when a natural gas line is installed through a process of trenchless drilling.

Image: Example of a cross bore

Trenchless drilling is used to avoid creating open trenches that can disturb roads, driveways, and gardens, but it relies on locates of existing utilities which may not always be accurate for various reasons. While a utility cross bore may not pose an immediate risk, it may become an issue if a sewer line needs to be cleared in the case of a blockage. This has resulted in some instances of property damage and injury, as a result of a gas leak, fire or explosion.

To address this risk, there is currently an emergency program in place called Call Before you Clear. This program relies solely on property owner and plumber participation and through this program over 10,000 annual inspections are completed. Still, many plumbers and homeowners do not call for an inspection prior to auguring their sewer lines. To expand inspections beyond the current emergency program, Enbridge Gas intends to implement a program to **proactively inspect and resolve additional utility cross bores** that may have been installed in the past. This would double the number of annual inspections.

Another program has been implemented by Enbridge Gas to **prevent new installations from creating new cross bores** even though that increases the cost of the installation and requires additional restoration work during the installation process.

These programs to proactively inspect and resolve existing cross bores and to prevent the creation of cross bores during the completion of new installations combined would cost customers $1.95 per year in 2024 increasing to $3.59 per year in 2028.

Connect to next page in the online version. All on one page there.

Which of the following is closest to your view?

[RANDOMIZE 01 AND 02]

01	Enbridge Gas should implement the proactive program to expand the number of inspections and continue with the preventative program to eliminate existing cross bores and prevent any new cross bores to maintain safety, at a cost of $1.95 per year in 2024 increasing to $3.59 in 2028 for the average customer.
02	Enbridge Gas should leave its processes of trenchless drilling as is and only resolve the cross bores that come up as an issue arises, even though this limits the inspections to those requested through the Call Before you Clear program, and may also create additional cross bores.
98	I don't have an opinion on this
99	Don't know

Comments:

Making Choices

Advanced Meter Infrastructure

The gas meter technology currently used by Enbridge Gas has not changed in many years. Enbridge Gas is working on a plan to rollout new advanced meters that would send usage information to Enbridge Gas through a wireless network, like your existing water or electricity usage meters. The meters also have additional functions that could allow Enbridge Gas to:

- ✓ Better detect and respond to possible gas leaks
- ✓ Enhance safety capabilities by enabling Enbridge Gas to remotely and automatically shutoff gas supply in the event of an emergency
- ✓ Allow for a reduction in greenhouse gas (GHG) emissions by reducing meter reader vehicles on the road
- ✓ Eliminate the need for estimated meter reads
- ✓ Provide customers detailed usage data information – this may also allow customers to be notified of faulty or left on appliances

Once all meters are rolled out, the above features would become available to all customers. Rates will increase as specified below, after which rates will decrease slowly and eventually decrease to levels lower than today as benefits are fully realized. How rates are impacted depends on timing of spend and realization of benefits.

Depending on the pace of rolling out automated meters, there are implications on the time the benefits listed above can be fully realized, and the cost involved for customers like you. These are outlined in the table below.

	Time to Fully Realize Benefits	First Year Cost (2024)	Maximum Annual Cost	Year that the Rate Impact reduces to Less than Today
Option 1	4 years	$3.25	$20.64 in 2028	2038
Option 2	8 years	$2.17	$14.88 in 2031	2039
Option 3	20 years	$1.40	$1.85 in 2026	2034

Which of the following is closest to your view? Across its service area, Enbridge Gas should …

01	Implement advanced meters **as soon as is feasible**, according to Option 1 above
02	Implement advanced meters at a **moderate pace**, according to Option 2 above
03	Implement advanced meters at a **slower pace**, according to Option 3 above
04	Replace meters only as required, even though this will prevent the additional benefits noted above from being realized
98	I don’t have an opinion on this
99	Don’t know

Comments:

Impact of Choices

Do You Want to Change Your Choices?

So far in this workbook, you have been asked about **7 key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page, you will find the annual bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential annual rate impact for 2024 and 2028 will be re-calculated each time you change one of your answers at the bottom of the page. Costs for 2025-2027 will fall between this range. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Compressor Stations:
Replace one compressor station
- □ **Included in the draft plan:** *Within the proposed increase ($2.43 in 2024 to 2028)*
- □ **Defer as long as possible:** *Though uncertain, at best it would decrease ($2.43 in 2024 to 2028)*

Proactive Vintage Steel Pipeline Replacement Program:
Replace 5,100 km of 17,000 km of vintage steel pipeline over the next 20 years
- □ **Included in the draft plan:** *Within the proposed increase ($0.81 in 2024 to $6.10 in 2028)*
- □ **Defer the proactive replacement for as long as possible:** *Decrease by $0.81 in 2024 to $6.10 in 2028*

Hydrogen gas:
Expand the current pilot project, and complete a system assessment
- □ **Add to the draft plan:** *$0.37 added to rates in 2024 and $0.24 in 2028*
- □ **No further spending on hydrogen:** *No change in rates*

Innovation and Technology Fund
Fund research into new low-carbon or energy efficient technologies
- □ **Add $1M fund to the plan:** *$0.26 added to rates in 2024 to 2028*
- □ **Add $5M fund to the plan:** *$1.28 added to rates in 2024 to 2028*
- □ **Add $10M fund to the plan:** *$2.56 added to rates in 2024 to 2028*
- □ **No fund:** *No change in rates*

Cut off at Main policy
Create a consistent policy across Enbridge Gas when customers need their gas line to be cut off at the main pipeline
- □ **User pay:** *homeowner portion of $3,700, not included within rates*
- □ **Middle ground:** *homeowner portion of $750, $0.25 added to rates in 2024 to $1.23 in 2028*
- □ **Shared among all:** *$0.30 in rates in 2024 to $1.52 in 2028*

Cross Bores
Implement proactive program to eliminate existing cross bores and prevent new ones
- □ **Proposed approach for proactive and preventative programs:** *$1.95 added to rates in 2024 to $3.59 in 2028*
- □ **No further spending on cross bores:** *No change in rates*

Advanced Meter Infrastructure
Identify the appropriate pace for installing advanced meters with enhanced safety and customer benefits
- □ **As soon as feasible: 4-year implementation:** *$3.25 added to rates in 2024 to $20.64 in 2028*
- □ **Moderate pace: 8-year implementation:** *$2.17 added to rates in 2024 to $10.27 in 2028*

The total impact of your choices would result in a range from:

+/- $X.XX in 2024 to +/- $X.XX in 2028

Note: these areas will be uniquely populated for each individual customer. The bill impacts of their individual responses will be summed and displayed below.

This would be a change from the estimated average increase of $22.05 in 2024 up to $86.32 in 2028 compared to October 2021 to your bill for distribution over the 5-year planning period that starts in 2024.

Enbridge Gas will be reviewing its plan based on the feedback you and other customers are sharing now. However, in doing that review, it is important for Enbridge Gas to get a sense of whether the current draft plan is generally acceptable or not. There were some choice options that Enbridge Gas had already included in the draft plan, and others that were not.

As mentioned earlier in the workbook, the Enbridge Gas plan for 2024 to 2028 focused on the following key objectives:

1. Maintaining system safety and reliability
2. Containing costs
3. Harmonizing rates and services
4. Preparing for the future

Currently the plan is estimated to result in an average annual increase of 1.9% over 2024 to 2028 for a total of 7.4% in 2028 compared to October 2021 rates. Along with your feedback on choices included within the plan, Enbridge Gas will consider your feedback on the choices that have not yet been included and update the plan accordingly.

Considering what you know about Enbridge Gas' plans, and the choices you have been making, which of the following best represents your point of view?

- ☐ Enbridge Gas should increase its investments, seeking to accelerate the programs shared in this workbook where possible, even if that means a higher draft increase over the 5-year period.
- ☐ Enbridge Gas should maintain the draft increase to deliver the programs shared in this workbook, focusing on its outlined objectives over the 5-year period.
- ☐ Enbridge Gas should reduce the draft increase, even if that could mean reductions in performance or increase safety or environmental risks over the 5-year period.
- ☐ Other **(please specify)**
- ☐ Don't know

Comments:

Service and Rate Harmonization

In its application to the OEB, Enbridge Gas is also considering several other items that may affect customers. In this section we will ask you about a few different things, including programs that it could offer, as well as some options on how rates are calculated and applied.

Infill Policy

When an existing home is located near a main line, it may receive a natural gas connection through the residential infill policy. Under regulations, existing customers cannot be charged for any of these expenses.

According to the policy, connections are provided to homeowners at no cost (because forecasted revenues from the new customer cover a portion of the cost to connect) up to a certain distance from the home to the main line. The cost for any extra distance must be paid by the homeowner.

These costs can be structured in different ways, and currently vary depending on whether someone is in the Legacy Enbridge Gas Distribution or Legacy Union Gas area. The more service length Enbridge Gas provides at no charge, the more needs to be charged for each extra metre of length to account for costs not covered by forecasted revenue.

Enbridge Gas would like to create a policy that is the same across the entire territory that reflects the cost of attaching a new customer and would like to ask you for your opinion.

Based on data from the last 3 years of installations, which is influenced by the current policies, the following proportion of installations would be free, while the remainder would pay an amount based on the length of their line. The historical average is shown in the table below.

	Length for free	Cost for remainder	Proportion of installations that would be free	Average cost for customers who would pay
Option 1	15m	$75/m	57%	43% pay an average of $635 for the remainder
Option 2	20m	$100/m	75%	25% pay an average of $1700 for the remainder
Option 3	25m	$140/m	84%	16% pay an average of $2885 for the remainder

Which of the following approaches is closest to your view?

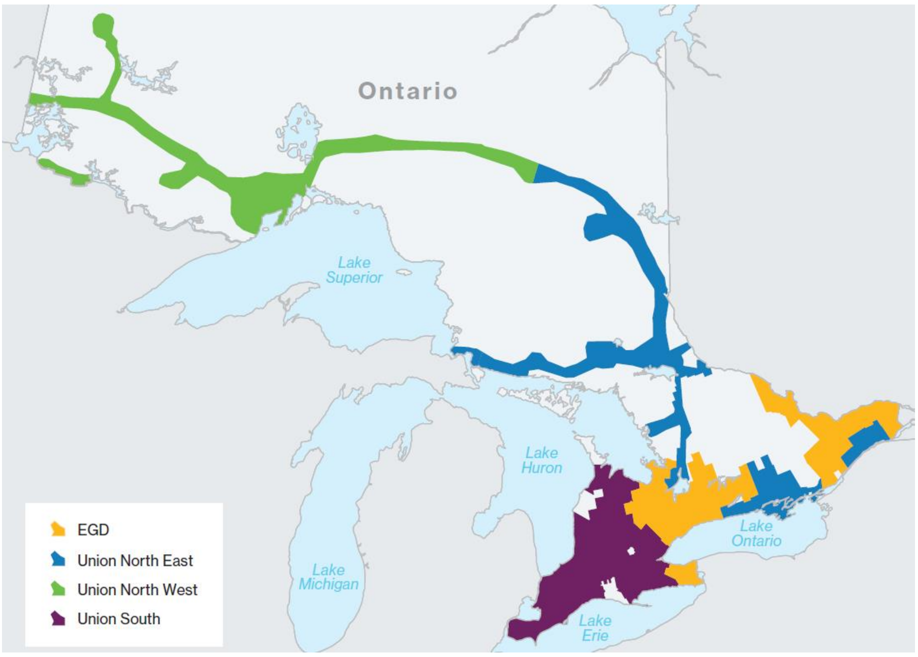
[RANDOMIZE 01 THROUGH 03 AND 03 THROUGH 01]

01	Enbridge Gas should offer 15 metres at no cost to the homeowner and charge $75/m for the remainder
02	Enbridge Gas should offer 20 metres at no cost to the homeowner and charge $100/m for the remainder
03	Enbridge Gas should offer 25 metres at no cost to the homeowner and charge $140/m for the remainder
98	I don’t have an opinion on this
99	Don’t know

Comments:

Rate Zones

Currently, the rate you pay for natural gas delivery depends on where you live in Ontario. As previously indicated, Enbridge Gas, today, is a combination of Legacy Enbridge Gas Distribution and Legacy Union Gas. Currently there are four rate zones, each with its own rates depending on where you are located, and which company previously served you. The four rate zones look as follows:



Enbridge Gas is considering the option of offering one rate zone for its different types of customers, regardless of location within Ontario and the cost to serve them. There are many benefits of one rate zone including similar charges for similar customers, a consistent customer experience, and reduced administrative costs.

One rate zone could result in a change to the amount customers pay for their natural gas service, and varies on the rate zone a customer is currently located in. The adjustment as a result of this change is impacted by the number of customers in a rate zone and is shown in the table below.

Current rate zone	Current average annual bill based on 2,400m3	Average cost adjustment at current rates
EGD	$1,149	Decrease of approximately 1% ($1 per month)
Union North East	$1,302	Decrease of approximately 10% ($10 per month)
Union North West	$1,230	Decrease of approximately 10% ($10 per month)
Union South	$1,018	Increase of approximately 5% ($5 per month)

REPRESENTATIVE SAMPLE ONLY: You are located in **(PIPE IN RATE ZONE BASED ON SAMPLE)**. Considering this, which of the following is closest to your view?
[RANDOMIZE 01 and 02]

01	Enbridge Gas should implement a single rate zone and make the rates for natural gas service the same across Ontario
02	Enbridge Gas should leave the rate zones as they are where customers pay different rates for natural gas service based on where they live
98	I don't have an opinion on this
99	Don't know

Comments:

Rate Design

Similar to your electric utility, your gas bill is split into the cost of the natural gas you use and the cost of delivering that gas to you. This question focuses on the delivery charge. Enbridge Gas incurs two types of costs in delivering natural gas to customers like you.

- **Variable costs** depend on how much natural gas you use.
- **Fixed costs** are the same regardless of how much natural gas you use.

The fixed costs that Enbridge Gas incurs can be divided into two groups: the cost of having access to the system, and the cost of the demand that you place on the system which drives the system capacity. We'll look at these two separately.

Cost of being connected to the system

One type of fixed cost is that of being connected to the system. This includes the cost of the pipeline, the pressure regulator, the natural gas meter, meter reading, billing, the contact centre and operations support. These costs are **fixed for Enbridge Gas** and are **similar for each customer** and do not change based on the size of the customer.

How do you feel **residential** customers like you should be billed for these costs of being connected to the system?

[RANDOMIZE 01 AND 02]

01	Each customer should pay a portion based on the amount of natural gas they use
02	The cost should be paid equally by customers of the same type (i.e. residential or business) regardless of how much natural gas they use
98	I don't have an opinion on this
99	Don't know

Cost of accessing a portion of the system

The other type of fixed cost is that of the system capacity. This includes the cost of the infrastructure, its operation, maintenance, and natural gas storage to meet the peak demand of customers on the coldest days of the year. These costs are **fixed for Enbridge Gas** but **may vary for each customer** based on their individual level of peak demand, which is often on the coldest days of the year.

How do you feel **residential** customers like you should be billed for these costs of accessing system capacity?

[RANDOMIZE 01 AND 02]

01	Each customer should pay a portion based on the amount of natural gas they use
02	The cost should be paid equally by customers of the same type (i.e. residential or business) regardless of how much natural gas they use
98	I don't have an opinion on this
99	Don't know

Comments:

Cost of the fuel

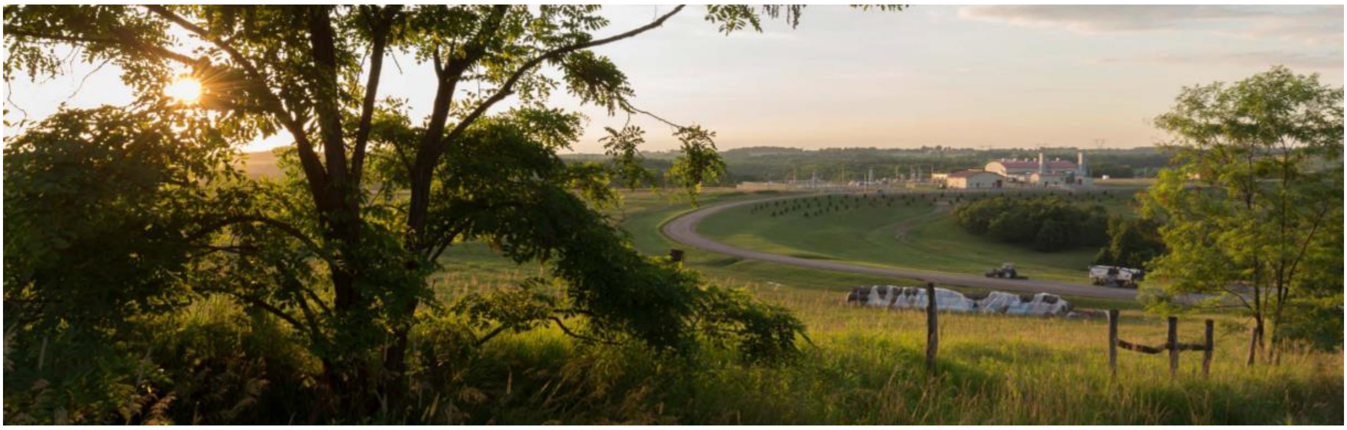
Fuel Choices

As previously discussed, the costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board and are passed on to customers at cost. However, Enbridge Gas can make some choices about the natural gas it purchases, beyond focusing on the lowest price in the market. We would like to ask you a couple of questions about gas supply options.

Responsibly Sourced Gas

Enbridge Gas is looking at options to ensure that the natural gas it purchases is responsibly sourced. This means that the companies who produce the natural gas adhere to higher standards than the minimum government standards. This relates to areas such as:

- minimizing impacts to air and water quality
- lowering GHG emissions during production
- stronger engagement with Indigenous communities, etc.



Enbridge Gas can offer some options to include Responsibly Sourced Gas in its portfolio, which can be purchased at a small premium. Responsibly Sourced Gas is a new and emerging trend in the North American natural gas industry. For this reason, current supply options are limited.

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 THROUGH 03 AND 03 THROUGH 01]

01	Enbridge Gas should commit to 10% of responsibly sourced gas in its gas supply which will cost the average customer $0.96/year
02	Enbridge Gas should commit to 25% of responsibly sourced gas in its gas supply which will cost the average customer $2.40/year
03	Enbridge Gas should commit to 50% of responsibly sourced gas in its gas supply which will cost the average customer $4.81/year
04	Enbridge Gas should **not** add any responsibly sourced gas to its gas supply if it increases rates by any amount
98	I don’t have an opinion on this
99	Don’t know

Comments:

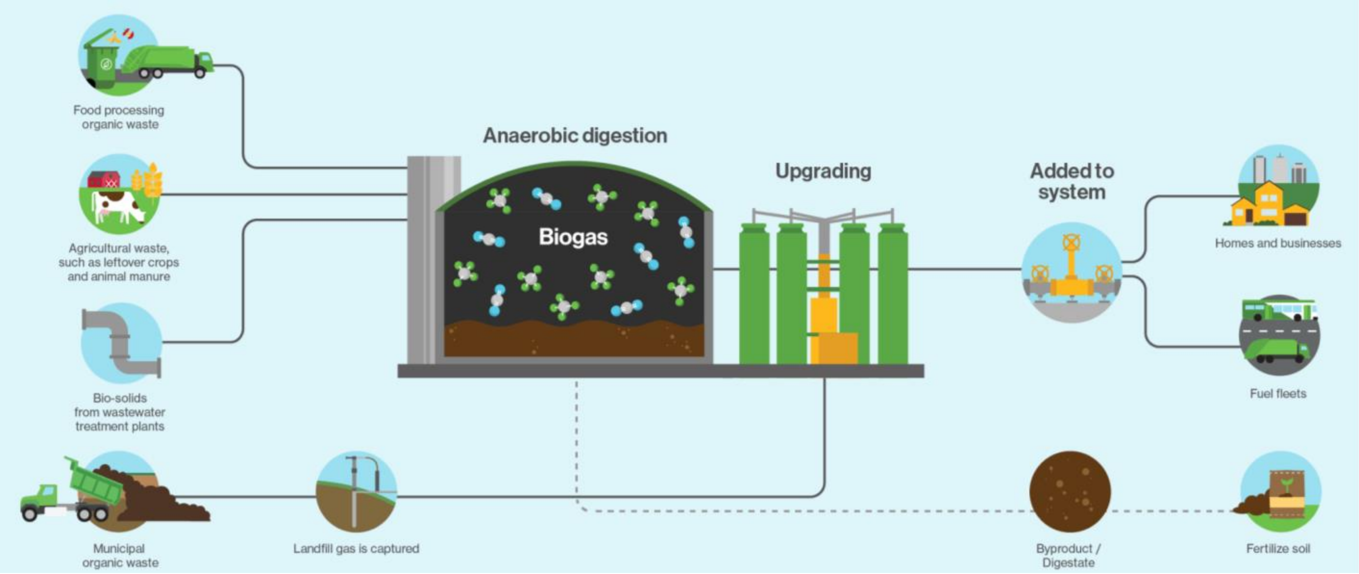
Cost of the fuel

Fuel Choices

Renewable Natural Gas

Enbridge Gas is looking at options to blend more Renewable Natural Gas (RNG) into the natural gas it delivers to green the gas supply. The gas is derived from organic waste from farms, landfills, and water treatment plants. The gas is then blended with traditional natural gas and supplied to customers using existing natural gas infrastructure.

RNG is considered to be carbon neutral and would reduce GHG emissions to help meet climate change targets. Every one percent of RNG in the gas supply reduces GHG emissions by one percent, in a 1:1 ratio. That means every additional 1% of RNG reduces your natural gas GHG emissions by 1%, and across the Enbridge Gas system, this is equivalent to taking 55,000 cars off the road.



Enbridge Gas is developing a plan to increase the blend of RNG in the gas system from 0.5% in 2025 to a higher amount over the course of the 2024 to 2028 plan and beyond. This amount is limited by the amount of RNG available in the market. Since the cost to produce RNG is currently higher than that of traditional natural gas it could have an impact on your rates.

The federal carbon charge would not be applied to the volume of RNG on customer bills, which is accounted for in the costs shown below.

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 THROUGH 03 AND 03 THROUGH 01]

01	Enbridge Gas should commit to increasing the amount of RNG in its gas supply to **8%** by 2030, which will cost the average customer $10.25/year in 2025 increasing to $135.73/year in 2030
02	Enbridge Gas should commit to increasing the amount of RNG in its gas supply to **5%** by 2030 which will cost the average customer $10.25/year in 2025 increasing to $84.83/year in 2030
03	Enbridge Gas should commit to increasing the amount of RNG in its gas supply to **2%** by 2030, which will cost the average customer $10.25/year in 2025 increasing to $33.93/year in 2030
04	Enbridge Gas should **not** add any RNG to its gas supply if it increases rates by any amount
98	I don't have an opinion on this
99	Don't know

Comments:

Final Thoughts

Feedback and More About You

Thank you for providing your input into the Enbridge Gas planning process. Your feedback will help ensure we submit a plan that will address our customers' needs and opinions. Before you finish, we would appreciate your answers to two brief topics. First, to help ensure we continue to improve our customer engagements, we would appreciate your feedback on this workbook. Second, sometimes particular groups of people have specific needs. We have some questions that will allow us to group your answers with other people like you. It should just take one or two more minutes to finish up.

Feedback on Enbridge Gas Customer Engagement

Enbridge Gas values your feedback. This is the first time the utility has conducted a review about its upcoming plans in this type of format.

Overall, did you have a favourable or unfavourable impression of the workbook you just completed?

- ❑ Very favourable
- ❑ Somewhat favourable
- ❑ Somewhat unfavourable
- ❑ Very unfavourable
- ❑ Don't know

In this workbook, do you feel that Enbridge Gas provided too much information, not enough, or just the right amount?

- ❑ Too little information
- ❑ Just the right amount of information
- ❑ Too much information

Was there any content missing that you would have liked to have seen included in this workbook?

- ❑ None

Is there anything that you would still like answered?

- ❑ None

Would you like to be notified by email about how Enbridge Gas used your feedback?

- ❑ Yes
- ❑ No

[IF "Yes"] Please enter you preferred email address: ______________________________________

About you

More About You

The following questions are for statistical purposes only. This information is used to segment and group similar people together when the survey results are analysed.

To what extent do you agree or disagree with the following statements?

The cost of my Enbridge Gas bill has a major impact on my finances and requires I do without some other important priorities.

- ❑ Strongly agree
- ❑ Somewhat agree
- ❑ Somewhat disagree
- ❑ Strongly disagree
- ❑ Don't know/No opinion

Customers are well served by the energy system in Ontario.

- ❑ Strongly agree
- ❑ Somewhat agree
- ❑ Somewhat disagree
- ❑ Strongly disagree
- ❑ Don't know/No opinion

Including yourself, how many people live in your household?

- ❑ Single person household
- ❑ 2 people
- ❑ 3 people
- ❑ 4 people
- ❑ 5 people
- ❑ 6 people
- ❑ 7 people
- ❑ 8 or more people
- ❑ Prefer not to say

Which of the following categories best describes the total annual income, after taxes, of all the members of your household?

- ❑ Less than $28,000
- ❑ $28,000 to less than $39,000
- ❑ $39,000 to less than $48,000
- ❑ $48,000 to less than $52,000
- ❑ $52,000 or more
- ❑ Prefer not to say

About you

More About You

Which gender identity do you most closely identify with?

- ❑ Man
- ❑ Woman
- ❑ Prefer to self-describe (Please specify)
- ❑ Prefer not to say

What age category do you fall into?

- ❑ Under 18
- ❑ 18-24
- ❑ 25-34
- ❑ 35-44
- ❑ 45-54
- ❑ 55-64
- ❑ 65-74
- ❑ 75 or older
- ❑ Prefer not to say

Are you an Indigenous person, that is First Nations (North American Indian), Métis or Inuk (Inuit)? *Please select all that apply.*

- ❑ No, not an Indigenous person
- ❑ Yes, First Nations
- ❑ Yes, Métis
- ❑ Yes, Inuk (Inuit)
- ❑ Don't know
- ❑ Prefer not to say

Approximately, how much was your most recent total Enbridge Gas bill?

$___________

❑ Don't know/not sure

Next Steps

Thank you for your input into our planning process. Enbridge Gas will use the findings from this consultation to ensure that its 2024-2028 plan meets customers' needs, which will be filed to the Ontario Energy Board as part of the Enbridge Gas 2024 Rate Rebasing application in Q4 2022.

Customer Engagement
Phase III: Workbook

GS (Business) Workbook

December 2021

About this Customer Engagement

Welcome to the Enbridge Gas Customer Engagement!

As Enbridge Gas plans for the future, it needs your input into choices that will impact the services you receive and the rates you pay.

- Enbridge Gas is looking for your feedback on its draft investment plan for 2024 and beyond to ensure that the plan reflects your needs and preferences.
- You don't need to be a natural gas expert to complete this workbook. It focuses on basic choices between outcomes that matter to you and provides the background information you need to answer the questions.
- The most important part of this workbook are the survey questions. While your view may not always align exactly with any of the options presented, please select the one that is closest. If you truly aren't sure, select the "don't know" option.

This workbook will take approximately 20-30 minutes to complete. Your progress will be saved as you move through the workbook, meaning you can leave and return to complete it at any time.

Those who complete the questions that follow will be invited to enter a draw to win one of two $500 cash prizes.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

If you are reading this on a smaller mobile device, you may wish to access the survey from a tablet, desktop or laptop instead, so that it is easier to read.

Background

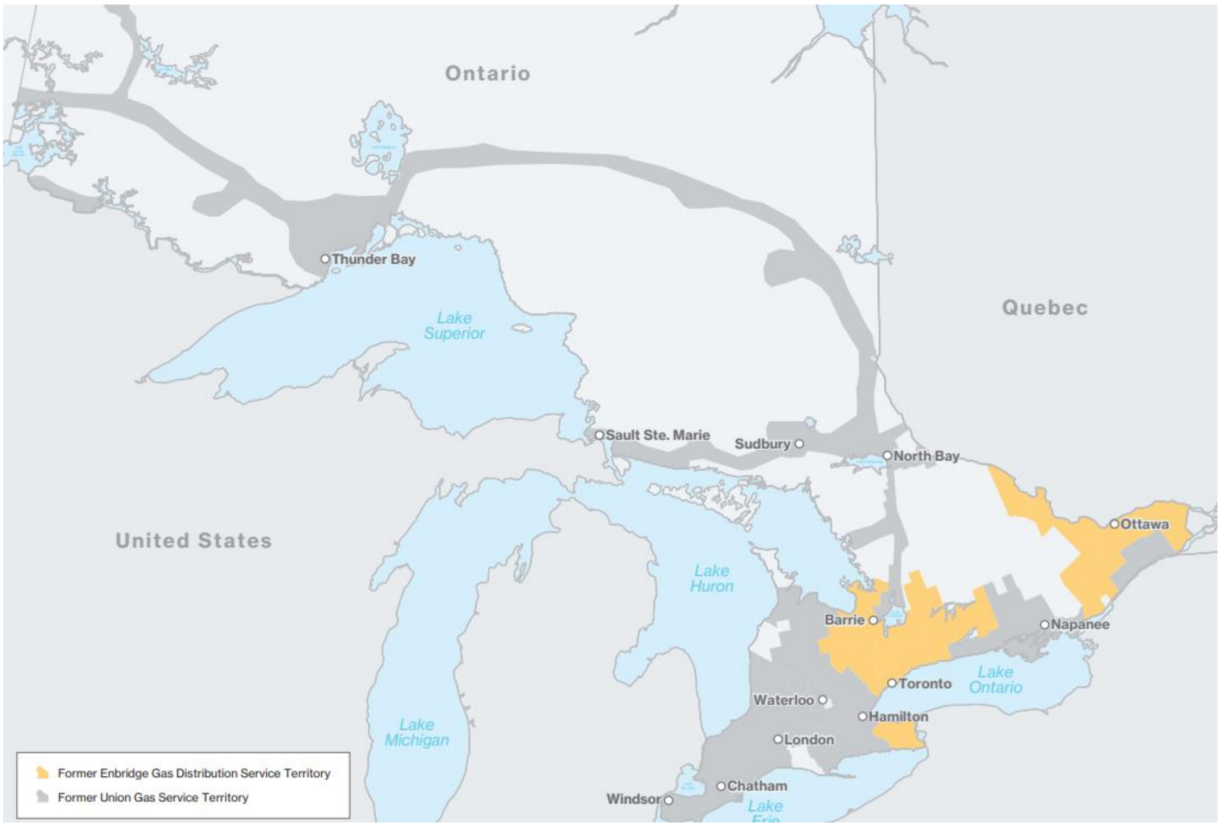
Who is Enbridge Gas?

Enbridge Gas Inc. is based in Ontario and delivers energy to customers in Ontario. Its parent company Enbridge Inc. is headquartered in Calgary, Canada, and operates across North America. Rates and business plans developed by Enbridge Gas must be approved by the Ontario Energy Board (the OEB), which regulates natural gas utilities in Ontario.

Enbridge Gas …

- ✓ Distributes natural gas to about 3.8 million residential, business and industrial customers
- ✓ Attaches more than 50,000 new customers each year
- ✓ Has agreements to provide gas distribution service within 313 municipalities and provides natural gas within 23 First Nations communities
- ✓ Has a network of over 151,500 kilometers of underground pipeline

In 2019, Enbridge Gas Distribution and Union Gas merged to form one company, Enbridge Gas Inc. Throughout this workbook we occasionally refer to Legacy Enbridge Gas Distribution and Legacy Union Gas (the previous companies), but mainly refer to the whole service area or territory that Enbridge Gas serves today.

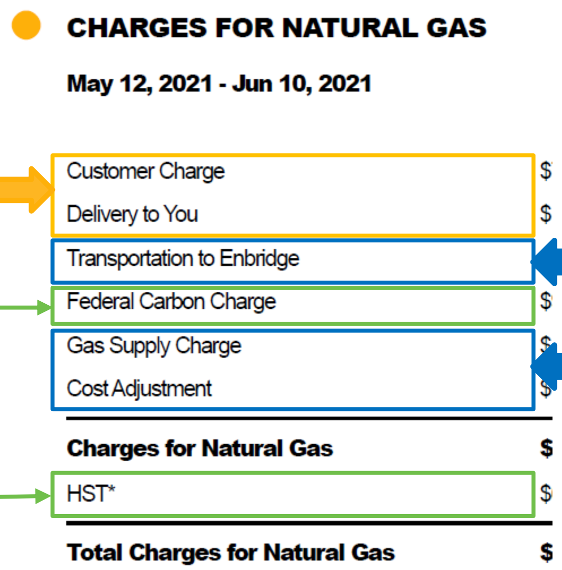


Background

Where do your rates go?

Below is an example of a natural gas bill.

The charges outlined in Orange are the costs of getting the gas to you once it reaches the Enbridge Gas system. At times, this may require a Rate Adjustment which, along with other rates, is determined through a regulatory process.



CHARGES FOR NATURAL GAS

May 12, 2021 - Jun 10, 2021

Customer Charge	$
Delivery to You	$
Transportation to Enbridge	
Federal Carbon Charge	$
Gas Supply Charge	$
Cost Adjustment	$
Charges for Natural Gas	**$**
HST*	$
Total Charges for Natural Gas	**$**

The charges outlined in Blue are the 'passed through' costs that pay for the natural gas you use (Gas Supply Charge and Cost Adjustment) and the cost of transporting it from where it is produced to the Enbridge Gas system (Transportation to Enbridge). If customers buy their natural gas through an energy marketer these costs would be subject to the agreement with the energy marketer.

Enbridge Gas is also responsible for collecting HST and the Federal Carbon Charge on behalf of the government. While some of these costs may be given back to customers in rebates, how these funds are used is determined by the government and is out of Enbridge Gas' control.

The pie chart below shows where the money goes.

The Blue slice shows the 'passed through' costs that pay for the natural gas and transportation to the Enbridge Gas system.

The money that goes to Enbridge Gas is in the other two slices.

- The Light Orange slice pays the capital costs of the infrastructure (such as pipes, compressors, buildings and other equipment) used to move and store natural gas across the system.
- The Dark Orange slice pays for operations – including the people who operate and maintain the equipment and the people who answer your calls and provide customer service.

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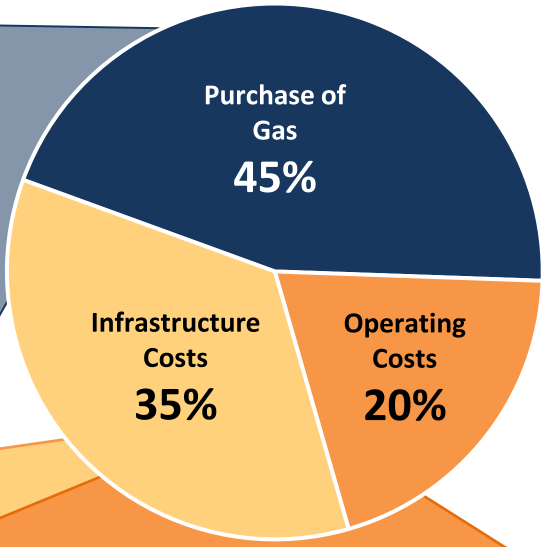
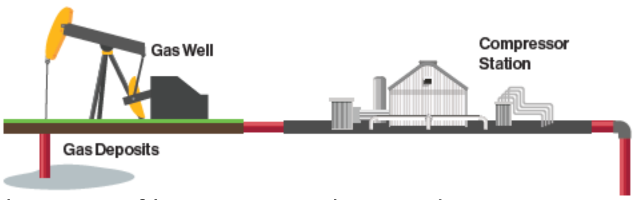
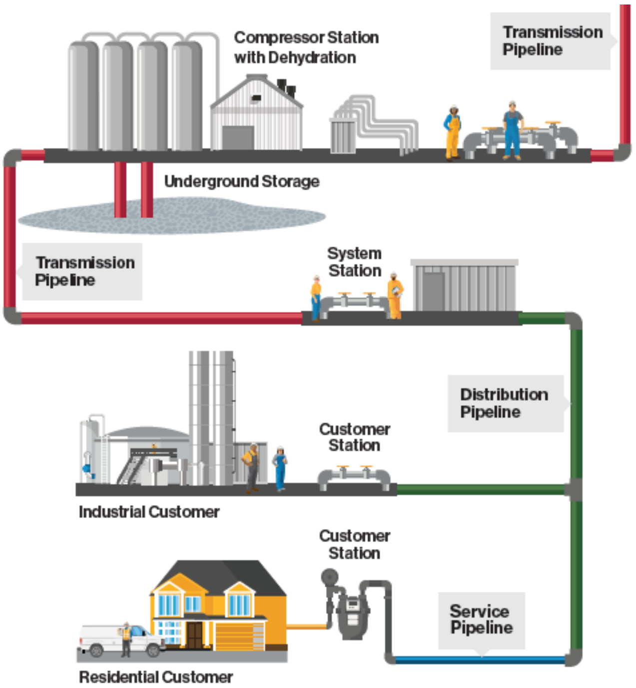


Purchase of Gas



The costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board, and are passed on to customers at cost.

Infrastructure



Once gas reaches the Enbridge Gas system, it is metered and then delivered to customers through a distribution system of local gas mains, small-diameter service lines and, ultimately, customer meters.

Natural gas is often stored in large underground reservoirs to help meet spikes in demand, particularly in winter.

Operations

Delivering gas to customers is just one part of Enbridge Gas' activities. Enbridge Gas provides a variety of supporting services to customers including:

- Manage and operate its call centres, ombudsperson offices, and its online My Account system to help customers manage their account online.
- Complete meter replacements, inspections, and respond to emergency calls.
- Conduct millions of meter readings each year.
- Offer programs to help customers reduce their natural gas usage. Since 1995, Enbridge Gas has saved its customers 30 billion lifetime cubic meters of natural gas and 56.2 million tonnes of greenhouse gas emissions, the equivalent of taking 12.2 million cars off the road for a year or heating 13.1 million natural gas homes for a year. These programs get approved by the Ontario Energy Board in a separate process and the costs for these programs are included in your rates.

Before this survey, how familiar were you with Enbridge Gas when it comes to delivering natural gas to homes and businesses in Ontario?

- ☐ Very familiar and could explain the details of the Enbridge Gas system to others
- ☐ Somewhat familiar with the Enbridge Gas system but could not explain the details to others
- ☐ Had heard of some of the terms mentioned, but knew very little about the Enbridge Gas system
- ☐ I knew nothing about the Enbridge Gas system
- ☐ Don't know

Where does this consultation fit?

Here in Ontario, customer views are central to the utility planning process.

- **Rates and business plans must be approved by the Ontario Energy Board (the OEB).**
- **The OEB requires that utilities consult with customers to understand your views on key trade-offs.**
- **In addition, the utilities must show how they took customer views into account when developing the plan.**

While some planning decisions will depend on detailed knowledge of engineering and industry standards, in other cases the choices will involve trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down. That is where you come in.

The diagram below shows how customers play a role at three points as Enbridge Gas develops and submits its business plan to the OEB.

How does Customer Engagement Impact Business Planning?

Enbridge Gas has developed a phased approach to gathering and responding to customer feedback.

✓ **1. Identify Customer Priorities**
In June through August of 2021, Enbridge Gas asked residential and business customers about their priorities for natural gas service.

✓ **2. Use Customer Feedback to Guide Development of Plan**
Enbridge Gas planners were given summaries of the key findings from the initial customer engagement to consider as they began building their plans.

You are here

3. Collect Customer Feedback on the Draft Plan
Now Enbridge Gas is returning to customers to get feedback on the draft plan and ask customers how the plan fits with their needs and preferences.

4. Re-Examine Plan
Enbridge Gas has an opportunity to make appropriate changes to the plan based on customer feedback.

5. Submit the Plan to the Ontario Energy Board (OEB)
Enbridge Gas will file the plan, with this workbook, and a summary report with the OEB, where it will be examined by the OEB, consumer advocates and other independent parties in a public hearing. **Customers** can view and comment on this application through the OEB website.

How well do you feel you understand how your feedback fits within the planning process?

□ Very well □ Somewhat well □ Not very well □ Not at all □ Don't know

Customer Experience

Satisfaction and Areas of Improvement

Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Is there anything in particular Enbridge Gas can do to improve their service to your organization? [OPEN]

How do you know if Enbridge Gas is doing a good job for your organization, or not? [OPEN]

Background

2024-2028 Plan

Plan Objectives

The Enbridge Gas business plan focuses on many of the same objectives as in the past years, as well as future challenges and pressures. Some of the high-level objectives of the plan are as follows:

1. **Maintain system safety and reliability** – ensure that the system continues to operate safely and reliably.
2. **Contain costs** – the OEB requires all utilities to "demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives".
3. **Harmonize rates and services** – ensure that the offerings are consistent across the entire service area as Enbridge Gas continues its merger activities.
4. **Prepare for the future** – ensure that the system is ready for low-carbon options, as well as offer options to help customers reduce their greenhouse gas (GHG) emissions.

Climate Change Goals

Compared to the past, Enbridge Gas' 2024-2028 plan places more emphasis on preparing for the future. Enbridge Gas is looking at ways in which it can support its organizational, as well as federal and provincial goals to reduce GHG emissions and achieve net zero targets.

- **Enbridge Inc. targets to reduce, from its operations, GHG emission intensity by 35% by 2030 over 2018 levels, and to reach Net Zero GHG emissions by 2050**
- **Federal targets to reduce GHG emissions by 40-45% by 2030 over 2005 levels and to reach Net Zero GHG emissions by 2050**
- **Provincial target to reduce GHG emissions by 30% by 2030 over 2005 levels**

How We Can Reduce GHG Emissions From Natural Gas

One of the ways in which GHG emissions are created is through the burning of fossil fuels such as coal, oil, and natural gas. Two key approaches can reduce the emissions from using natural gas:

- by blending lower carbon fuels into the gas supply, including Renewable Natural Gas (RNG) and Hydrogen gas, and
- by improving energy efficiency of homes and businesses, and implementing new, lower-emitting technologies.

Each of these could introduce new, higher, costs that would be passed on to customers but would mitigate costs that might be required to introduce other programs or options to reduce overall GHG emissions in Ontario and Canada. **Later in the workbook we will ask about your views on these potential costs.**

Do these objectives seem like the right approach or the wrong approach?
☐ Right approach ☐Wrong approach ☐ Don't know

Is there anything you would change about this approach or any other comments you would like to make?
Comments:

Calculating Rates

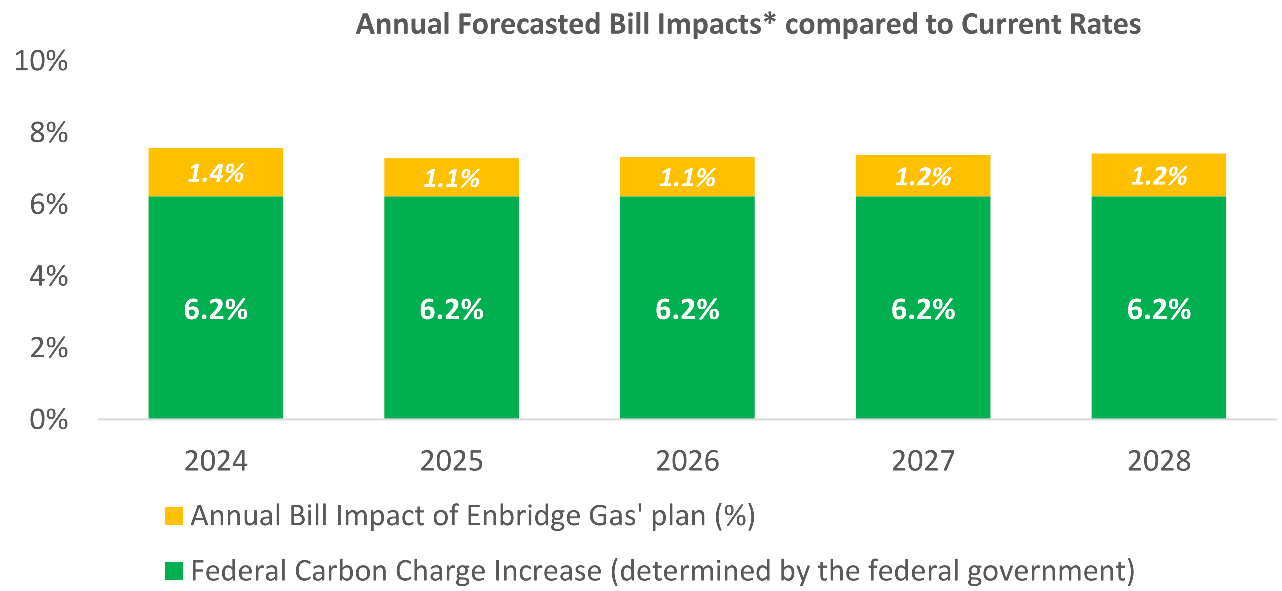
When looking at its overall objectives, and its budgets, there are many items that Enbridge Gas must consider that affect its costs, and in turn the rates that customers pay. Some of these items are determined by regulatory requirements, others by external factors in the market, and again others by decisions made by Enbridge Gas.

There are **accounting policies and factors** that affect expenditures. These include proposals through which Enbridge Gas manages business risk and how it calculates the depreciation of its assets. These types of proposals contribute significantly to the overall rate impact shown in the "Forecasted Bill Increase" below and are partially offset by savings in other areas. While these issues are too technical for this workbook, they will be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Operating expenses make up about 20% of Enbridge Gas' overall expenditures. Current estimates show that these expenses would increase somewhat over the 2024-2028 period, with the highest annual increase at 1.5%, which is less than inflation. Decisions on operating expenses are based on industry best practices and generally do not involve trade-offs between customer outcomes. Since these are technical issues, they will also be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Capital expenses make up about 35% of Enbridge Gas' overall expenditures and pay for investments in its equipment that have lasting benefits over many years. Since capital spending includes major one-off projects as well as ongoing maintenance and replacement, capital spending varies from year to year. The questions in the next section focus on these choices.

The *Forecasted Bill Impacts* for 2024 to 2028 compared to current rates are shown below. Compared to your current rates, rates in 2022 are expected to increase by 2.1% for the average commercial customer, while 2023 rates are not yet established.



These charges for business customers may vary somewhat by rate class, and in all cases where we're showing a rate impact, it is the highest potential impact across rate classes.

**These estimates are preliminary and are subject to both your feedback and ongoing work to review as Enbridge Gas planners continue to work on their plans. This does not include any potential changes in the fuel costs or the federal carbon charge.*

How well do you feel you understand the projected increase in your rates from 2024 to 2028?
☐ Very well ☐ Somewhat well ☐ Not very well ☐ Not at all ☐ Don't know

Making Choices

In this next section of the workbook, we will ask you about some of the key items that Enbridge Gas is considering in its plan that see trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down.

Some of these items are currently included in the draft budget, while others will need to be added to the budget depending on further analysis and feedback from customers like you.

For each question, where applicable, the financial impact is expressed as the percentage impact each year on an average business customer bill. The actual impact will depend on your own individual usage.

At the end of the section, you will have an opportunity to review your responses and their impact on your bill. You will then be able to adjust your choices to provide what you feel is the best balance.

Compression Stations

Enbridge Gas has 50 Compressors, 7 Dehydrators and supporting equipment. These are required to ensure that the gas that is injected into storage or into the distribution system meets the quality specifications and to move gas along the transmission system.

As compressors age, they experience breakdowns on an increasingly frequent basis – when equipment manufacturers stop supporting these compressors, the time to complete repairs can be extensive leading to reliability and gas quality problems. There are two compressors that will need to be replaced in the coming years.

When considering a project to replace compressors like this, Enbridge Gas looks at various options:

- ✓ Replacing one larger compressor with two smaller ones,
- ✓ Using alternative fuel sources such as electricity or hydrogen gas, and
- ✓ Preparing for outages by having spare parts available.

In this case, however, there is a lack of viable alternatives at the specific locations for the two compressor stations, so Enbridge Gas is planning to replace one compressor station in 2026, with the other one being replaced after 2028 to use the existing stations for as long as possible.

Not doing this work increases the risk the station could fail. This may require Enbridge Gas to buy more gas on the market (if available), rather than drawing gas from its storage. This introduces the risk of price volatility, as gas purchased on the market during the coldest days of the year has been up to 220% more expensive in the past 5 years than the gas that could be drawn from storage.

Image: inside a building housing a compressor station

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Furthermore, if the station fails, replacement will still be required which would take a couple of years of construction to complete, extending the risks for longer. The replacement of the first compressor station is planned for 2026 and would cost the average customer 0.028%/year. Which of the following statements best represents your point of view?

[RANDOMIZE 01 and 02]

01	Enbridge Gas should replace the compressor stations as it currently plans, replacing one compressor station during the period of its 2024-2028 plan, at an increase of 0.028%
02	Enbridge Gas should defer the compressor station project for as long as possible, even though this carries with it increasing risk of outages and with that, greater price volatility. The cost of this is subject to market prices at the time.
98	I don’t have an opinion on this
99	Don’t know

Comments:

Making Choices

Vintage Steel Pipeline Replacement Program

Enbridge Gas has implemented a Vintage Steel Pipeline Replacement Program, which focuses on replacing older steel pipelines within the system. It is considering ramping up the program to ensure ongoing safety and reliability of the distribution system and to prepare the network for the eventual delivery of low carbon, blended hydrogen. Blended hydrogen can safely be delivered through modern steel and plastic distribution systems – however, with the rapid introduction of natural gas to Ontario during the 1950's and 60's, Enbridge Gas has a lot of older steel pipelines which are nearing end of life and require replacement in a planned and proactive manner.

This program would see an increase in work and a ramp-up of spending starting in 2024 with the goal of replacing 5,100 km of 17,000 km of vintage steel pipelines in 20 years. These vintage steel pipelines were built before 1971 and are more prone to failures compared to steel pipelines built later due to materials, construction and damage prevention practices used at the time. Using risk assessments, the program will focus on replacing pipelines that are closest to end of life first.

Enbridge Gas intends to start this increase in work in 2024 so that the work can be spread out over a longer period with a limited increase to internal resources. Pushing the work into the future, such as 10 years from now, to achieve the same objectives, will require additional internal as well as external resource overheads and costs, with reduced productivity due to a sharper ramp-up of skilled labour. The overall costs would be expected to be higher with a delayed approach.

It is estimated that this program, ramping up in 2024, included in the capital budget, is equivalent to an average annual increase of 0.2%/year from 0.05% increasing to a total of 0.38% in 2028 for the average business customer.

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 and 02]

01	Enbridge Gas should increase its spending on the Vintage Steel Replacement Program in order to help prepare the system for the future by starting to ramp-up the work in 2024 at an average annual increase of 0.2%/year from 0.05% increasing to a total of 0.38% in 2028.
02	Enbridge Gas should defer proactive replacement of its system that would prepare it for the future – even if this means that the cost will be higher in the future.
98	I don't have an opinion on this
99	Don't know

Comments:

Making Choices

Hydrogen Gas

Enbridge Gas is looking at options to blend more Hydrogen gas into the natural gas it delivers to green the gas supply.

Clean hydrogen gas is derived from surplus clean electrical energy that is converted to hydrogen gas through electrolysis technology. The gas is then blended with traditional natural gas, reducing GHG emissions.

Enbridge Gas is considering investing more in clean hydrogen as a tool for reducing GHG emissions in Ontario to allow for additional hydrogen gas to be blended into the natural gas distribution system. This would mean expanding the pilot project at the power-to-gas (P2G) facility in Markham where hydrogen gas is currently being produced, to deliver hydrogen-blended natural gas to a larger network of customers, expanding the blended gas area from approximately 3,600 to just under 17,000 customers.

Image: Hydrogen gas can be stored in tanks

Additionally, Enbridge Gas intends to launch a feasibility study that assesses the full system's readiness for more hydrogen gas to be included in the system. The costs for these projects for the average customer are estimated as follows:

	2024	2025 and 2026	2027 and 2028
Annual cost	0.004%	0.005%	0.018%

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 and 02]

01	Enbridge Gas should implement these plans for hydrogen gas, which will increase the average business customer's bill by 0.004% in 2024, increasing to 0.005% in 2025 and 2026 and 0.018% in 2027 and 2028, including the cost of the hydrogen gas.
02	Enbridge Gas should not implement these plans related to Hydrogen gas to reduce GHG emissions and keep rates as low as possible
98	I don't have an opinion on this
99	Don't know

Comments:

Making Choices

Innovation and Technology Fund

Enbridge Gas can support the advancement of various new low-carbon or energy efficient technologies that may not be available to consumers today.

While some of this work is already taking place on a small scale, the budget for these types of projects is currently very limited. Additional contributions from customers would allow Enbridge Gas to expand this type of research and development work.

Similar to other jurisdictions, Enbridge Gas is considering an **Innovation and Technology Fund** in order to support the research, development, and the bringing to market of new low-carbon or energy efficient technologies. Where possible, this would be in partnership with other utilities and organizations.

Some options include funding for …

- new research on energy efficiency technologies,
- hydrogen gas,
- renewable natural gas, or
- carbon capture, utilization and sequestration (CCUS). This is the process of capturing carbon dioxide before it enters the atmosphere and either use it as a resource to create products or permanently storing it underground.

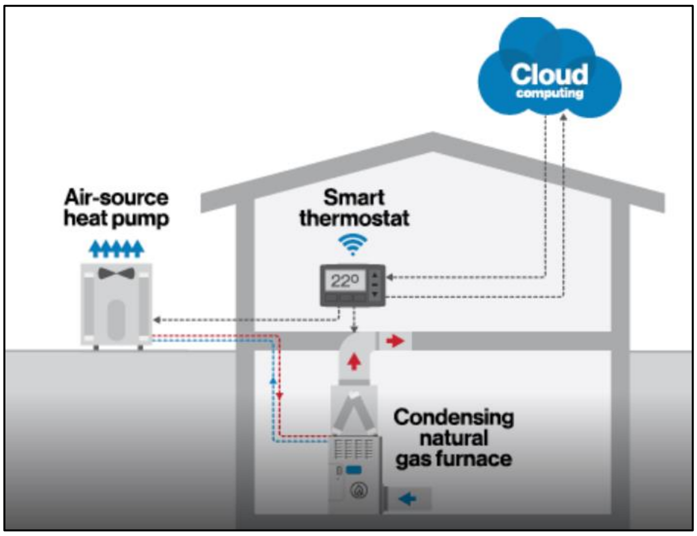


Image: Ontario pilot program tests future of advanced hybrid heating

The more money in this fund, the more projects could be completed, however Enbridge Gas is committed to finding a right balance of spending and planning for the future.

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 THROUGH 03 AND 03 THROUGH 01]

01	Enbridge Gas should develop this fund, spending $1M/year which would increase the average business customer’s bill by 0.003%/year
02	Enbridge Gas should develop this fund, spending $5M/year which would increase the average business customer’s bill by 0.014%/year
03	Enbridge Gas should develop this fund, spending $10M/year which would increase the average business customer’s bill by 0.029%/year
04	Enbridge Gas should **not** develop a fund to invest in new low-carbon or energy efficient technologies
98	I don’t have an opinion on this
99	Don’t know

Comments:

Making Choices

Cross Bores

While rare, it is possible that a natural gas line may intersect with a sewer line. When this happens, it is called a utility cross bore. This is unintentionally created when a natural gas line is installed through a process of trenchless drilling.

Image: Example of a cross bore

Trenchless drilling is used to avoid creating open trenches that can disturb roads, driveways, and gardens, but it relies on locates of existing utilities which may not always be accurate for various reasons. While a utility cross bore may not pose an immediate risk, it may become an issue if a sewer line needs to be cleared in the case of a blockage. This has resulted in some instances of property damage and injury, as a result of a gas leak, fire or explosion.

To address this risk, there is currently an emergency program in place called Call Before you Clear. This program relies solely on property owner and plumber participation and through this program over 10,000 annual inspections are completed. Still, many plumbers and homeowners do not call for an inspection prior to auguring their sewer lines. To expand inspections beyond the current emergency program, Enbridge Gas intends to implement a program to **proactively inspect and resolve additional utility cross bores** that may have been installed in the past. This would double the number of annual inspections.

Another program has been implemented by Enbridge Gas to **prevent new installations from creating new cross bores** even though that increases the cost of the installation and requires additional restoration work during the installation process.

These programs to proactively inspect and resolve existing cross bores and to prevent the creation of cross bores during the completion of new installations combined would increase the average business customer's bill by 0.02% per year in 2024 increasing to $0.04% per year in 2028.

Which of the following is closest to your view?

[RANDOMIZE 01 AND 02]

Connect to next page in the online version. All on one page there.

01	Enbridge Gas should implement the proactive program to expand the number of inspections and continue with the preventative program to eliminate existing cross bores and prevent any new cross bores to maintain safety, at an increase of 0.02% per year in 2024 increasing to 0.04% in 2028 for the average customer.
02	Enbridge Gas should leave its processes of trenchless drilling as is and only resolve the cross bores that come up as an issue arises, even though this limits the inspections to those requested through the Call Before you Clear program, and may also create additional cross bores.
98	I don’t have an opinion on this
99	Don’t know

Comments:

Making Choices

Advanced Meter Infrastructure

The gas meter technology currently used by Enbridge Gas has not changed in many years. Enbridge Gas is working on a plan to rollout new advanced meters that would send usage information to Enbridge Gas through a wireless network, like your existing water or electricity usage meters. The meters also have additional functions that could allow Enbridge Gas to:

- ✓ Better detect and respond to possible gas leaks
- ✓ Enhance safety capabilities by enabling Enbridge Gas to remotely and automatically shutoff gas supply in the event of an emergency
- ✓ Allow for a reduction in greenhouse gas (GHG) emissions by reducing meter reader vehicles on the road
- ✓ Eliminate the need for estimated meter reads
- ✓ Provide customers detailed usage data information – this may also allow customers to be notified of faulty or left on appliances or equipment

Once all meters are rolled out, the above features would become available to all customers. Rates will increase as specified below, after which rates will decrease slowly and eventually decrease to levels lower than today as benefits are fully realized. How rates are impacted depends on timing of spend and realization of benefits.

Depending on the pace of rolling out automated meters, there are implications on the time the benefits listed above can be fully realized, and the cost involved for customers like you. These are outlined in the table below.

	Time to Fully Realize Benefits	First Year Increase (2024)	Maximum Annual Increase	Year that the Rates Impact Reduces to Less than Today
Option 1	4 years	0.04%	0.23% in 2028	2038
Option 2	8 years	0.02%	0.17% in 2031	2039
Option 3	20 years	0.02%	0.02% in 2026	2034

Which of the following is closest to your view? Across its service area, Enbridge Gas should …

01	Implement advanced meters **as soon as is feasible**, according to Option 1 above
02	Implement advanced meters at a **moderate pace**, according to Option 2 above
03	Implement advanced meters at a **slower pace**, according to Option 3 above
04	Replace meters only as required, even though this will prevent the additional benefits noted above from being realized
98	I don't have an opinion on this
99	Don't know

Comments:

Impact of Choices

Do You Want to Change Your Choices?

So far in this workbook, you have been asked about **6 key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page, you will find the annual bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential annual rate impact for 2024 and 2028 will be re-calculated each time you change one of your answers at the bottom of the page. Costs for 2025-2027 will fall between this range. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Compressor Stations:
Replace one compressor station
- ☐ **Included in the draft plan:** *Within the proposed increase (0.028% in 2024 to 2028)*
- ☐ **Defer as long as possible:** *Though uncertain, at best it would decrease (0.028% in 2024 to 2028)*

Proactive Vintage Steel Pipeline Replacement Program:
Replace 5,100 km of 17,000 km of vintage steel pipeline over the next 20 years
- ☐ **Included in the draft plan:** *Within the proposed increase (0.05% in 2024 to 0.38% in 2028)*
- ☐ **Defer the proactive replacement for as long as possible:** *Decrease by 0.05% in 2024 to 0.38% in 2028*

Hydrogen Gas:
Expand the current pilot project, and complete a system assessment
- ☐ **Add to the draft *plan:*** *0.004% in 2024, 0.018% in 2028*
- ☐ **No further spending on hydrogen:** *No change in rates*

Innovation and Technology Fund:
Fund research into new low-carbon or energy efficient technologies
- ☐ **Add $1M fund to the plan:** *Increase by 0.003%/year*
- ☐ **Add $5M fund to the plan:** *Increase by 0.014%/year*
- ☐ **Add $10M fund to the plan:** *Increase by 0.029%/year*
- ☐ **No fund:** *No change in rates*

Cross Bores:
Implement proactive program to eliminate existing cross bores and prevent new ones
- ☐ **Proposed approach for proactive and preventative programs:** *0.02% added to rates in 2024 to 0.04% in 2028*
- ☐ **No further spending on cross bores:** *No change in rates*

Advanced Meter Infrastructure:
Identify the appropriate pace for installing advanced meters with enhanced safety and customer benefits
- ☐ **As soon as feasible: 4-year implementation:** *0.04% added to rates in 2024 to 0.23% in 2028*
- ☐ **Moderate pace: 8-year implementation:** *0.02% added to rates in 2024 to 0.12% in 2028*
- ☐ **Slower pace: 20-year implementation:** *0.02% added to rates in 2024 to 0.02% in 2028*
- ☐ **Replace as required:** *No change in rates*

The total impact of your choices would result in a range from:

+/- xx% in 2024 to +/- xx% in 2028

Note: these areas will be uniquely populated for each individual customer. The bill impacts of their individual responses will be summe and displayed below.

This would be a change from the estimated average increase of 1.4% in 2024 up to 5.9% in 2028 compared to October 2021 to your bill for distribution over the 5-year planning period that starts in 2024.

Enbridge Gas will be reviewing its plan based on the feedback you and other customers are sharing now. However, in doing that review, it is important for Enbridge Gas to get a sense of whether the current draft plan is generally acceptable or not. There were some choice options that Enbridge Gas had already included in the draft plan, and others that were not.

As mentioned earlier in the workbook, the Enbridge Gas plan for 2024 to 2028 focused on the following key objectives:

1. Maintaining system safety and reliability
2. Containing costs
3. Harmonizing rates and services
4. Preparing for the future

Currently the plan is estimated to result in an average annual increase of 1.4% over 2024 to 2028 for a total of 5.9% in 2028 compared to October 2021 rates. Along with your feedback on choices included within the plan, Enbridge Gas will consider your feedback on the choices that have not yet been included and update the plan accordingly.

Considering what you know about Enbridge Gas’ plans, and the choices you have been making, which of the following best represents your point of view?

- □ Enbridge Gas should increase its investments, seeking to accelerate the programs shared in this workbook where possible, even if that means a higher draft increase over the 5-year period.
- □ Enbridge Gas should maintain the draft increase to deliver the programs shared in this workbook, focusing on its outlined objectives over the 5-year period.
- □ Enbridge Gas should reduce the draft increase, even if that could mean reductions in performance or increase safety or environmental risks over the 5-year period.
- □ Other **(please specify)**
- □ Don’t know

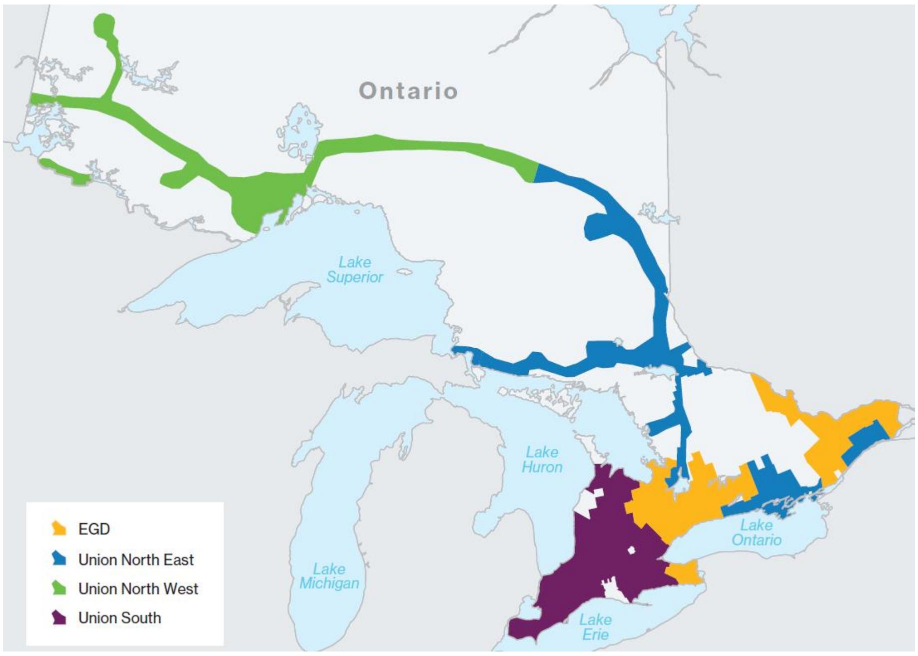
Comments:

Service and Rate Harmonization

In its application to the OEB, Enbridge Gas is also considering several other items that may affect customers. In this section we will ask you about a few different things, including programs that it could offer, as well as some options on how rates are calculated and applied.

Rate Zones

Currently, the rate you pay for natural gas delivery depends on where you are in Ontario. As previously indicated, Enbridge Gas, today, is a combination of Legacy Enbridge Gas Distribution and Legacy Union Gas. Currently there are four rate zones, each with its own rates depending on where you are located, and which company previously served you. The four rate zones look as follows:



Enbridge Gas is considering the option of offering one rate zone for its different types of customers, regardless of location within Ontario and the cost to serve them. There are many benefits of one rate zone including similar charges for similar customers, a consistent customer experience, and reduced administrative costs.

One rate zone could result in a change to the amount customers pay for their natural gas service, and varies on the rate zone a customer is currently located in. The adjustment as a result of this change is impacted by the number of customers in a rate zone and is shown in the table below.

Current rate zone	Average cost adjustment at current rates
EGD	Decrease of approximately 1%
Union North East	Decrease of approximately 10%
Union North West	Decrease of approximately 10%
Union South	Increase of approximately 5%

You are located in **(PIPE IN RATE ZONE BASED ON SAMPLE)**.
Considering this, which of the following is closest to your view?
[RANDOMIZE 01 and 02]

01	Enbridge Gas should implement a single rate zone and make the rates for natural gas service the same across Ontario
02	Enbridge Gas should leave the rate zones as they are where customers pay different rates for natural gas service based on where they live
98	I don't have an opinion on this
99	Don't know

Rate Design

Similar to your electric utility, your gas bill is split into the cost of the natural gas you use and the cost of delivering that gas to you. This question focuses on the delivery charge. Enbridge Gas incurs two types of costs in delivering natural gas to customers like you.

- **Variable costs** depend on how much natural gas you use.
- **Fixed costs** are the same regardless of how much natural gas you use.

The fixed costs that Enbridge Gas incurs can be divided into two groups: the cost of having access to the system, and the cost of the demand that you place on the system which drives the system capacity. We'll look at these two separately.

Cost of being connected to the system

One type of fixed cost is that of being connected to the system. This includes the cost of the pipeline, the pressure regulator, the natural gas meter, meter reading, billing, the contact centre and operations support. These costs are **fixed for Enbridge Gas** and are **similar for each customer** and do not change based on the size of the customer.

How do you feel **business** customers like you should be billed for these costs of being connected to the system?

[RANDOMIZE 01 AND 02]

01	Each customer should pay a portion based on the amount of natural gas they use
02	The cost should be paid equally by customers of the same type (i.e. residential or business) regardless of how much natural gas they use
98	I don't have an opinion on this
99	Don't know

Cost of accessing a portion of the system

The other type of fixed cost is that of the system capacity. This includes the cost of the infrastructure, its operation, maintenance, and natural gas storage to meet the peak demand of customers on the coldest days of the year. These costs are **fixed for Enbridge Gas** but **may vary for each customer** based on their individual level of peak demand, which is often on the coldest days of the year.

How do you feel business customers like you should be billed for these costs of accessing system capacity?

[RANDOMIZE 01 AND 02]

01	Each customer should pay a portion based on the amount of natural gas they use
02	The cost should be paid equally by customers of the same type (i.e. residential or business) regardless of how much natural gas they use
98	I don't have an opinion on this
99	Don't know

Comments:

Cost of the fuel

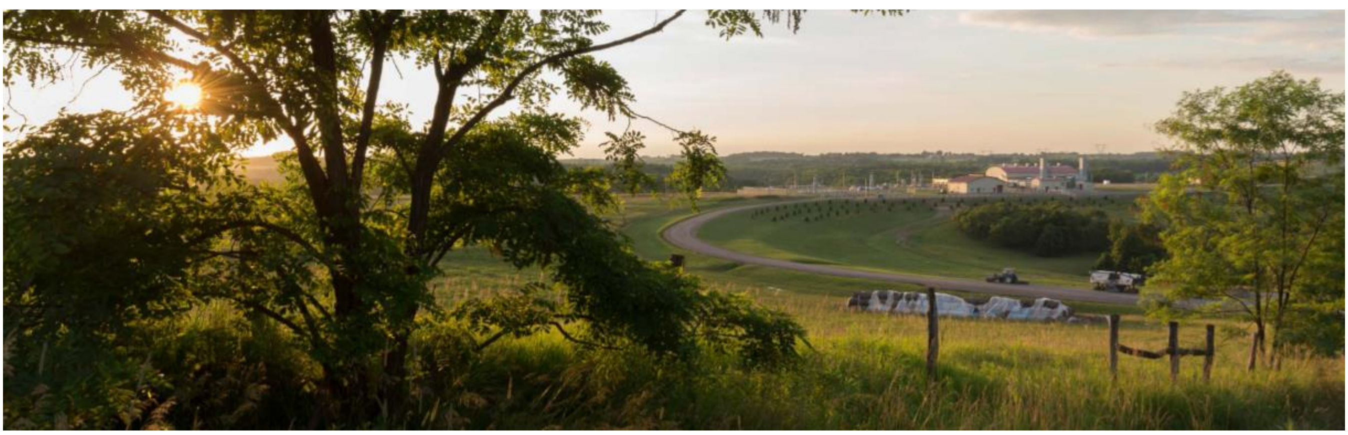
Fuel Choices

As previously discussed, the costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board and are passed on to customers at cost. However, Enbridge Gas can make some choices about the natural gas it purchases, beyond focusing on the lowest price in the market. We would like to ask you a couple of questions about gas supply options.

Responsibly Sourced Gas

Enbridge Gas is looking at options to ensure that the natural gas it purchases is responsibly sourced. This means that the companies who produce the natural gas adhere to higher standards than the minimum government standards. This relates to areas such as:

- minimizing impacts to air and water quality
- lowering GHG emissions during production
- stronger engagement with Indigenous communities, etc.



Enbridge Gas can offer some options to include Responsibly Sourced Gas in its portfolio, which can be purchased at a small premium. Responsibly Sourced Gas is a new and emerging trend in the North American natural gas industry. For this reason, current supply options are limited.

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 THROUGH 03 AND 03 THROUGH 01]

01	Enbridge Gas should commit to 10% of responsibly sourced gas in its gas supply which will cost the average business customer an additional 0.13%/year
02	Enbridge Gas should commit to 25% of responsibly sourced gas in its gas supply which will cost the average business customer an additional 0.32%/year
03	Enbridge Gas should commit to 50% of responsibly sourced gas in its gas supply which will cost the average business customer an additional 0.63%/year
04	Enbridge Gas should **not** add any responsibly sourced gas to its gas supply if it increases rates by any amount
98	I don’t have an opinion on this
99	Don’t know

Comments:

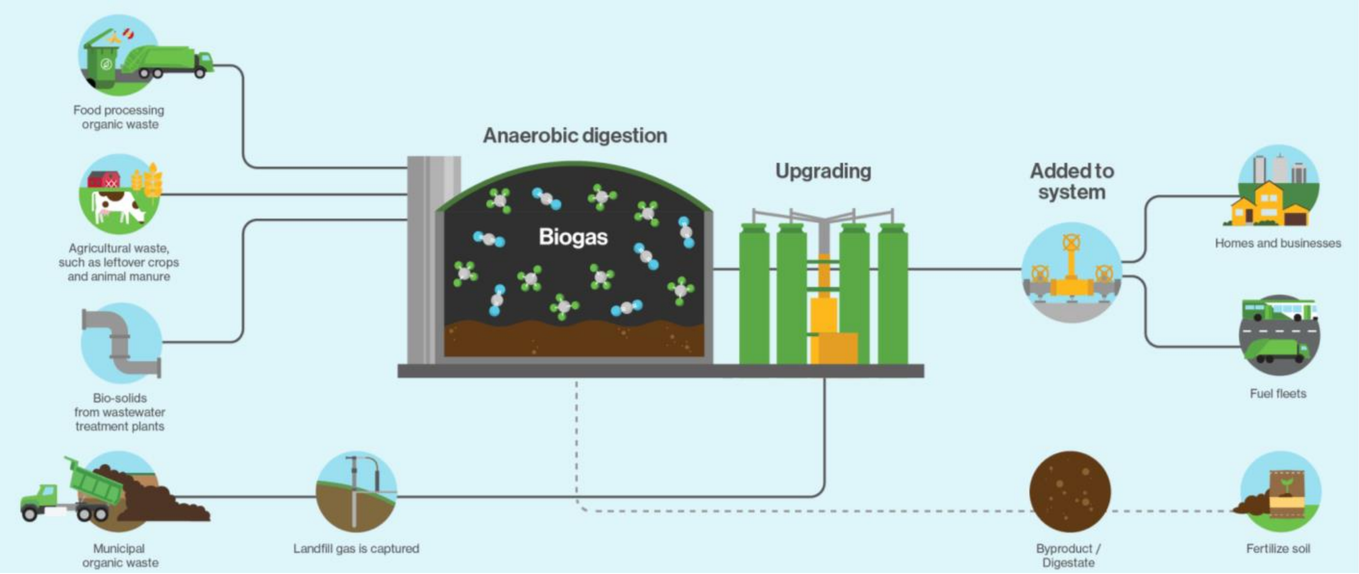
Cost of the fuel

Fuel Choices

Renewable Natural Gas

Enbridge Gas is looking at options to blend more Renewable Natural Gas (RNG) into the natural gas it delivers to green the gas supply. The gas is derived from organic waste from farms, landfills, and water treatment plants. The gas is then blended with traditional natural gas and supplied to customers using existing natural gas infrastructure.

RNG is considered to be carbon neutral and would reduce GHG emissions to help meet climate change targets. Every one percent of RNG in the gas supply reduces GHG emissions by one percent, in a 1:1 ratio. That means every additional 1% of RNG reduces your natural gas GHG emissions by 1%.



Enbridge Gas is developing a plan to increase the blend of RNG in the gas system from 0.5% in 2025 to a higher amount over the course of the 2024 to 2028 plan and beyond. This amount is limited by the amount of RNG available in the market. Since the cost to produce RNG is currently higher than that of traditional natural gas it could have an impact on your rates.

The federal carbon charge would not be applied to the volume of RNG on customer bills, which is accounted for in the costs shown below.

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 THROUGH 03 AND 03 THROUGH 01]

01	Enbridge Gas should commit to increasing the amount of RNG in its gas supply to **8%** by 2030, which will cost the average business customer 1.3%/year in 2025 increasing to 17.8% in 2030
02	Enbridge Gas should commit to increasing the amount of RNG in its gas supply to **5%** by 2030 which will cost the average business customer 1.3%/year in 2025 increasing to 11.2% in 2030
03	Enbridge Gas should commit to increasing the amount of RNG in its gas supply to **2%** by 2030, which will cost the average business customer 1.3%/year in 2025 increasing to 4.5% in 2030
04	Enbridge Gas should **not** add any RNG to its gas supply if it increases rates by any amount
98	I don't have an opinion on this
99	Don't know

Comments:

Final Thoughts

Feedback and More About Your Business

Thank you for providing your input into the Enbridge Gas planning process. Your feedback will help ensure we submit a plan that will address our customers' needs and opinions. Before you finish, we would appreciate your answers to two brief topics. First, to help ensure we continue to improve our customer engagements, we would appreciate your feedback on this workbook. Second, sometimes particular groups of customers have specific needs. We have some questions that will allow us to group your answers with other customers like you. It should just take one or two more minutes to finish up.

Feedback on Enbridge Gas Customer Engagement

Enbridge Gas values your feedback. This is the first time the utility has conducted a review about its upcoming plans in this type of format.

Overall, did you have a favourable or unfavourable impression of the workbook you just completed?

- ❑ Very favourable
- ❑ Somewhat favourable
- ❑ Somewhat unfavourable
- ❑ Very unfavourable
- ❑ Don't know

In this workbook, do you feel that Enbridge Gas provided too much information, not enough, or just the right amount?

- ❑ Too little information
- ❑ Just the right amount of information
- ❑ Too much information

Was there any content missing that you would have liked to have seen included in this workbook?

- ❑ None

Is there anything that you would still like answered?

- ❑ None

Would you like to be notified by email about how Enbridge Gas used your feedback?

- ❑ Yes
- ❑ No

[IF "Yes"] Please enter you preferred email address: ____

About you

More About Your Business

The following questions are for statistical purposes only. This information is used to segment and group similar customers together when the survey results are analysed.

To what extent do you agree or disagree with the following statements?

The cost of my Enbridge Gas bill has a major impact on my business' finances and requires the business do without some other important priorities.

- ❑ Strongly agree
- ❑ Somewhat agree
- ❑ Somewhat disagree
- ❑ Strongly disagree
- ❑ Don't know/No opinion

Customers are well served by the energy system in Ontario.

- ❑ Strongly agree
- ❑ Somewhat agree
- ❑ Somewhat disagree
- ❑ Strongly disagree
- ❑ Don't know/No opinion

How do you use natural gas at your organization? Please check as many as apply.

- ❑ Natural gas is used in production process
- ❑ Natural gas is used as feedstock
- ❑ Natural gas is used for heating or space conditioning
- ❑ Natural gas is used for water heating
- ❑ Other
- ❑ Don't know

Including yourself, how many people work at your organization?

- ❑ 1 person
- ❑ 2 to 5 people
- ❑ 6 to 10 people
- ❑ 11 to 25 people
- ❑ 26 to 50 people
- ❑ More than 50 people
- ❑ Don't know

Approximately, how much was your most recent total Enbridge Gas bill?

$___________

❑ Don't know/not sure

Next Steps

Thank you for your input into our planning process. Enbridge Gas will use the findings from this consultation to ensure that its 2024-2028 plan meets customers' needs, which will be filed to the Ontario Energy Board as part of the Enbridge Gas 2024 Rate Rebasing application in Q4 2022.

Customer Engagement
Phase III: Workbook

Contract Customer Workbook

January 2022

STRICTLY PRIVILEGED AND CONFIDENTIAL

About this Customer Engagement

Welcome to the Enbridge Gas Customer Engagement!

As Enbridge Gas plans for the future, it needs your input into choices that will impact the services you receive and the rates you pay.

- Enbridge Gas is looking for your feedback on its draft investment plan for 2024 and beyond to ensure that the plan reflects your needs and preferences.
- Enbridge Gas' contract customers are important to its business and their views are important.

This is Enbridge Gas' first rate application and investment plan since the merger of Union Gas and Enbridge Gas Distribution, and it will address a large number of issues that could affect your rates and services. In addition to the workbook itself, there are also links to videos that explain the proposals for contract rate distribution services, and direct purchase services in more detail.

We want to hear from you on all those changes, so we are asking for an hour or so of your time.

You don't have to do this all at once. Your progress will be saved as you move through the workbook, so you can leave and return to complete it at any time.

While this engagement is dealing with all the issues that may affect you in one comprehensive conversation, future engagements could conduct several smaller conversations. We will ask you for your feedback on this choice near the end

Those who complete the questions that follow will be invited to enter a draw to win one of two $500 cash prizes.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

If you are reading this on a smaller mobile device, you may wish to access the survey from a tablet, desktop or laptop instead, so that it is easier to read.

While many customer are familiar with natural gas contract terminology, you can click **here** to open a list of acronyms in a separate window.

Background

Who is Enbridge Gas?

Company Overview

Enbridge Gas Inc. is based in Ontario and delivers energy to customers in Ontario. Its parent company Enbridge Inc. is headquartered in Calgary, Canada, and operates across North America. Rates and business plans developed by Enbridge Gas must be approved by the Ontario Energy Board (the OEB), which regulates natural gas utilities in Ontario.

Enbridge Gas …

- ✓ Distributes natural gas to about 3.8 million residential, business and industrial customers
- ✓ Attaches more than 50,000 new customers each year
- ✓ Has agreements to provide gas distribution service within 313 municipalities and provides natural gas within 23 First Nation communities
- ✓ Has a network of over 151,500 kilometers of underground pipeline

In 2019, Enbridge Gas Distribution and Union Gas merged to form one company, Enbridge Gas Inc. Throughout this workbook we occasionally refer to Legacy Enbridge Gas Distribution and Legacy Union Gas (the previous companies), but mainly refer to the whole service area or territory that Enbridge Gas serves today.

The Storage and Transmission Market

In addition to providing distribution services to customers in our franchise area, Enbridge Gas serves the surrounding storage and transmission marketplace. The Dawn Hub is the largest integrated underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canadian and U.S. supply basins to markets in central Canada, the Great Lakes region and the northeast U.S.

The Dawn-Parkway transmission system is a series of four transmission pipelines (229 km/143 mi), and compressor stations that move natural gas through Ontario from the Dawn Hub near Sarnia, east to the Parkway compressor facility near Mississauga. At Parkway, the system connects with other pipelines that serve residents in the Toronto area, Quebec, eastern Canada and the U.S. northeast.

Enbridge Gas Customer Engagement

Background

Where do your rates go?

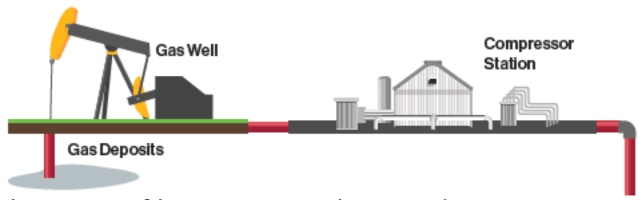
The pie chart below shows where the money goes.

The Blue slice shows the 'pass through' costs that pay for the natural gas and transportation to the Enbridge Gas system.

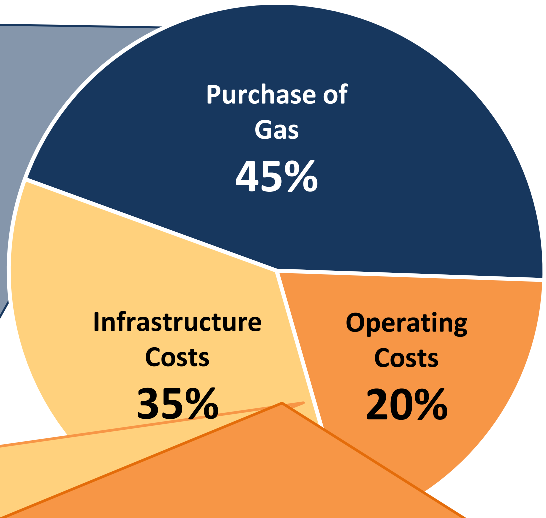
The money that goes to Enbridge Gas is in the other two slices.

- The Light Orange slice pays the capital costs of the infrastructure (such as pipes, compressors, buildings and other equipment) used to move and store natural gas across the system.
- The Dark Orange slice pays for operations – including the people who operate and maintain the equipment and the people who answer your calls and provide customer service.

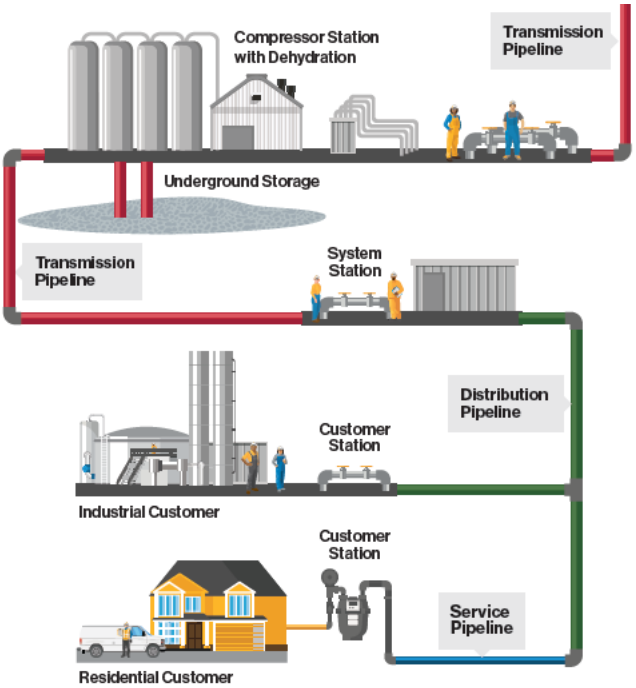
Purchase of Gas



The costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board, and are passed on to customers at cost.



Infrastructure



Once gas reaches the Enbridge Gas system, it is metered and then delivered to customers through a distribution network of local gas mains, small-diameter service lines and, ultimately, customer meters.

Natural gas is often stored in large underground reservoirs to help meet spikes in demand, particularly in winter.

Operations

Delivering gas to customers is just one part of Enbridge Gas' activities. Enbridge Gas employees provide a variety of supporting services to customers including:

- ✓ Manage and operate its call centres, ombudsperson offices, and its online My Account system to help customers manage their account online.
- ✓ Complete meter replacements, inspections, and respond to emergency calls.
- ✓ Conduct millions of meter readings each year.
- ✓ Offer programs to help customers reduce their natural gas usage. Since 1995, Enbridge Gas has saved its customers 30 billion lifetime cubic meters of natural gas and 56.2 million tonnes of greenhouse gas emissions, the equivalent of taking 12.2 million cars off the road for a year or heating 13.1 million natural gas homes for a year. These programs get approved by the Ontario Energy Board in a separate process and the costs for these programs are included in your rates.

Before this survey, how familiar were you with Enbridge Gas when it comes to delivering natural gas to homes and businesses in Ontario?

- ☐ Very familiar and could explain the details of the Enbridge Gas system to others
- ☐ Somewhat familiar with the Enbridge Gas system but could not explain the details to others
- ☐ Had heard of some of the terms mentioned, but knew very little about the Enbridge Gas system
- ☐ I knew nothing about the Enbridge Gas system
- ☐ Don't know

Where does this consultation fit?

Here in Ontario, customer views are central to the utility planning process.

- **Rates and business plans must be approved by the Ontario Energy Board (the OEB).**
- **The OEB requires that utilities consult with customers to understand your views on key trade-offs.**
- **In addition, the utilities must show how they took customer views into account when developing the plan.**

While some planning decisions will depend on detailed knowledge of engineering and industry standards, in other cases the choices will involve trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down. That is where you come in.

The diagram below shows how customers play a role as Enbridge Gas develops and submits its business plan to the OEB.

How does Customer Engagement Impact Business Planning?

Enbridge Gas has developed a phased approach to gathering and responding to customer feedback.

✓ **1. Information Gathering and Issue Identification**
Enbridge Gas planners gathered information and identified key issues to address in its plans. This process included review of previous research engagements, as well as informal conversations with customers and industry associations to identify customer needs and priorities.

✓ **2. Develop the Draft Plan**
Enbridge Gas planners use the key findings from the information gathering and issue identification phase as they began building their plans.

You are here

3. Collect Customer Feedback on the Draft Plan
Enbridge Gas is asking customers for feedback on the draft plan and how the plan fits with their needs and preferences.

4. Re-Examine Plan
Enbridge Gas has an opportunity to make appropriate changes to the plan based on customer feedback.

5. Submit the Plan to the Ontario Energy Board (OEB)
Enbridge Gas will file the plan, with this workbook, and a summary report with the OEB, where it will be examined by the OEB, consumer advocates and other independent parties in a public hearing. **Customers** can view and comment on this application through the OEB website.

How well do you feel you understand how your feedback fits within the planning process?

☐ Very well ☐ Somewhat well ☐ Not very well ☐ Not at all ☐ Don't know

Customer Experience

Satisfaction and Areas of Improvement

The Ontario Energy Board (OEB) expects Enbridge Gas to develop a plan that will focus on cost effective delivery of outcomes that matter to customers.

Overall experience

Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Comments:

Is there anything in particular Enbridge Gas can do to improve their service to you? [OPEN]

Customer Experience

Satisfaction and Areas of Improvement

Contract customers have a unique set of needs compared to other rate classes. The following questions will help us understand how well we are currently meeting your needs and where there is room for improvement.

Overall customer service

Taking into consideration all aspects of Enbridge Gas' customer service, how satisfied are you with Enbridge Gas' customer service?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Comments:

Firm distribution service

Firm distribution service offers firm deliveries of natural gas to the end use customer every day of the year. This is the most common service.

How satisfied are you with the reliability of Enbridge Gas' firm distribution services?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Comments:

Seasonal distribution service

Seasonal distribution service is a form of firm service that provides access to firm deliveries of natural gas in months where Enbridge Gas does not expect to see peak demand on the system. This service is tailored for customers who do not have their peak demands in the winter.

Do you contract for seasonal distribution service today?

- ☐ Yes
- ☐ No

If yes:

How satisfied are you with Enbridge Gas' current seasonal distribution services?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Comments:

Customer Experience

Satisfaction and Areas of Improvement

Interruptible distribution service

Interruptible distribution service can be added to firm distribution service or can be contracted separately. This service allows Enbridge Gas to issue a notice of interruption that requires an end user to reduce their consumption completely, or to reduce it to the level of firm service they have contracted.

Do you contract for interruptible distribution service today?

- ◻ Yes
- ◻ No

If yes:

How satisfied are you with Enbridge Gas' current interruptible distribution services?

- ◻ Very satisfied
- ◻ Somewhat satisfied
- ◻ Neither satisfied nor dissatisfied
- ◻ Somewhat dissatisfied
- ◻ Very dissatisfied
- ◻ Don't know

Comments:

Why do you use interruptible distribution service?

- ◻ Less expensive
- ◻ Natural gas is not a primary energy source
- ◻ Firm distribution service is not available (I would prefer firm service if available)
- ◻ Avoids distribution overrun charges
- ◻ Other: _______
- ◻ Don't know

Are there any other reasons that you use interruptible distribution service? Please indicate them below:

Customer Experience

Customer Outcomes

In considering its business plan to be implemented starting in 2024, Enbridge Gas must make many decisions. We would like your feedback on the outcomes you would like Enbridge Gas to focus on in its plan. Outcomes are the goals and priorities that matter to you.

There is a list of broad outcomes that Enbridge Gas will need to consider. Using a scale from 0 to 10, where 0 means "not at all important" and 10 means "extremely important", please tell us how important each one is to you. Be sure to save a rating of 10 for those items that are most important to you.

Outcomes (randomize)	**Importance Rating (0-10, don't know)**
Reliably delivering natural gas	
Safely delivering natural gas	
Making good use of the money customers pay	
Providing affordable pricing	
Providing predictable pricing	
Providing dependable customer service	
Minimizing any impacts on the environment	
Being socially responsible	
Supporting the growth of Ontario's economy	

Are there any other outcomes that are not listed above that are important to you? Please indicate them below:

Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which ones would you rank as first, second and third, in terms of importance to you.

Outcomes	**Ranking, 1st, 2nd, 3rd**
Reliably delivering natural gas	
Safely delivering natural gas	
Making good use of the money customers pay	
Providing affordable pricing	
Providing predictable pricing	
Providing dependable customer service	
Minimizing any impacts on the environment	
Being socially responsible	
Supporting the growth of Ontario's economy	
Other:	

Background

2024-2028 Plan

Plan Objectives

The Enbridge Gas business plan focuses on many of the same objectives as in the past years, as well as future challenges and pressures. Some of the high-level objectives of the plan are as follows:

1. **Maintain system safety and reliability** – ensure that the system continues to operate safely and reliably.
2. **Contain costs** – the OEB requires all utilities to "demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives".
3. **Harmonize rates and services** – ensure that the offerings are consistent across the entire service area as Enbridge Gas continues its merger activities.
4. **Prepare for the future** – ensure that the system is ready for low-carbon options, as well as offer options to help customers reduce their greenhouse gas (GHG) emissions.

Climate Change Goals

Compared to the past, Enbridge Gas' 2024-2028 plan places more emphasis on preparing for the future. Enbridge Gas is looking at ways in which it can support its organizational, as well as federal and provincial goals to reduce GHG emissions and achieve net zero targets.

- **Enbridge Inc. targets to reduce, from its operations, GHG emission intensity by 35% by 2030 over 2018 levels, and to reach Net Zero GHG emissions by 2050**
- **Federal targets to reduce GHG emissions by 40-45% by 2030 over 2005 levels and to reach Net Zero GHG emissions by 2050**
- **Provincial target to reduce GHG emissions by 30% by 2030 over 2005 levels**

How We Can Reduce GHG Emissions From Natural Gas

One of the ways in which GHG emissions are created is through the burning of fossil fuels such as coal, oil, and natural gas. Two key approaches can reduce the emissions from using natural gas:

- by blending lower carbon fuels into the gas supply, including Renewable Natural Gas (RNG) and Hydrogen gas, and
- by improving energy efficiency of homes and businesses, and implementing new, lower-emitting technologies.

Each of these could introduce new, higher, costs that would be passed on to customers but would mitigate costs that might be required to introduce other programs or options to reduce overall GHG emissions in Ontario and Canada. **Later in the workbook we will ask about your views on these potential costs.**

Do these objectives seem like the right approach or the wrong approach?
□ Right approach □ Wrong approach □ Don't know

Is there anything you would change about this approach or any other comments you would like to make?
Comments:

Calculating Rates

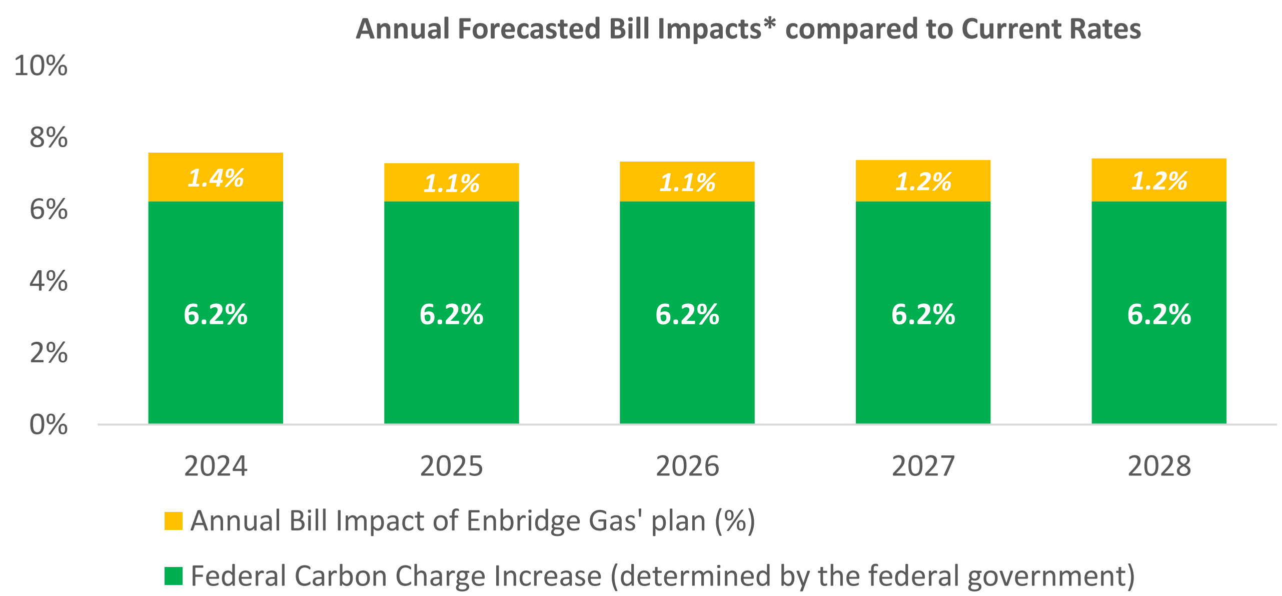
When looking at its overall objectives, and its budgets, there are many items that Enbridge Gas must consider that affect its costs, and in turn the rates that customers pay. Some of these items are determined by regulatory requirements, others by external factors in the market, and again others by decisions made by Enbridge Gas.

There are **accounting policies and factors** that affect expenditures. These include proposals through which Enbridge Gas manages business risk and how it calculates the depreciation of its assets. These types of proposals contribute significantly to the overall rate impact shown in the "Forecasted Bill Impacts" below and are partially offset by savings in other areas. While these issues are too technical for this workbook, they will be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Operating expenses make up about 20% of Enbridge Gas' overall expenditures. Current estimates show that these expenses would increase somewhat over the 2024-2028 period, with the highest annual increase at 1.5%, which is less than inflation. Decisions on operating expenses are based on industry best practices and generally do not involve trade-offs between customer outcomes. Since these are technical issues, they will also be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Capital expenses make up about 35% of Enbridge Gas' overall expenditures and pay for investments in its equipment that have lasting benefits over many years. Since capital spending includes major one-off projects as well as ongoing maintenance and replacement, capital spending varies from year to year. The questions in the next section focus on these choices.

The *Forecasted Bill Impacts* for 2024 to 2028 compared to current rates are shown below. Compared to your current rates, rates in 2022 are expected to increase by 2.1% for the average commercial customer, while 2023 rates are not yet established.



These charges for business customers may vary somewhat by rate class, and in all cases where we're showing a rate impact, it is the highest potential impact across rate classes.

**These estimates are preliminary and are subject to both your feedback and ongoing work to review as Enbridge Gas planners continue to work on their plans. This does not include any potential changes in the fuel costs or the federal carbon charge.*

How well do you feel you understand the projected increase in your rates from 2024 to 2028?
□ Very well □ Somewhat well □ Not very well □ Not at all □ Don't know

Making Choices

In this next section of the workbook, we will ask you about some of the key items that Enbridge Gas is considering in its plan that see trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down.

Some of these items are currently included in the draft budget, while others will need to be added to the budget depending on further analysis and feedback from customers like you.

For each question, where applicable, the financial impact is expressed as the percentage impact each year on an average business customer bill. The actual impact will depend on your own individual usage.

At the end of the section, you will have an opportunity to review your responses and their impact on your bill. You will then be able to adjust your choices to provide what you feel is the best balance.

Compression Stations

Enbridge Gas has 50 Compressors, 7 Dehydrators and supporting equipment. These are required to ensure that the gas that is injected into storage or into the distribution system meets the quality specifications and to move gas along the transmission system.

As compressors age, they experience breakdowns on an increasingly frequent basis – when equipment manufacturers stop supporting these compressors, the time to complete repairs can be extensive leading to reliability and gas quality problems. There are two compressors that will need to be replaced in the coming years.

When considering a project to replace compressors like this, Enbridge Gas looks at various options:

- ✓ Replacing one larger compressor with two smaller ones,
- ✓ Using alternative fuel sources such as electricity or hydrogen gas, and
- ✓ Preparing for outages by having spare parts available.

In this case, however, there is a lack of viable alternatives at the specific locations for the two compressor stations, so Enbridge Gas is planning to replace one compressor station in 2026, with the other one being replaced after 2028 to use the existing stations for as long as possible.

Not doing this work increases the risk the station could fail. This may require Enbridge Gas to buy more gas on the market (if available), rather than drawing gas from its storage. This introduces the risk of price volatility, as gas purchased on the market during the coldest days of the year has been up to 220% more expensive in the past 5 years than the gas that could be drawn from storage.

Image: inside a building housing a compressor station

Furthermore, if the station fails, replacement will still be required which would take a couple of years of construction to complete, extending the risks for longer. The replacement of the first compressor station is planned for 2026 and would cost the average customer 0.028%/year. Which of the following statements best represents your point of view?

[RANDOMIZE 01 and 02]

	Enbridge Gas should replace the compressor stations as it currently plans, replacing one

Making Choices

Vintage Steel Pipeline Replacement Program

Enbridge Gas has implemented a Vintage Steel Pipeline Replacement Program, which focuses on replacing older steel pipelines within the system. It is considering ramping up the program to ensure ongoing safety and reliability of the distribution system and to prepare the network for the eventual delivery of low carbon, blended hydrogen. Blended hydrogen can safely be delivered through modern steel and plastic distribution systems – however, with the rapid introduction of natural gas to Ontario during the 1950's and 60's, Enbridge Gas has a lot of older steel pipelines which are nearing end of life and require replacement in a planned and proactive manner.

This program would see an increase in work and a ramp-up of spending starting in 2024 with the goal of replacing 5,100 km of 17,000 km of vintage steel pipelines in 20 years. These vintage steel pipelines were built before 1971 and are more prone to failures compared to steel pipelines built later due to materials, construction and damage prevention practices used at the time. Using risk assessments, the program will focus on replacing pipelines that are closest to end of life first.

Enbridge Gas intends to start this increase in work in 2024 so that the work can be spread out over a longer period with a limited increase to internal resources. Pushing the work into the future, such as 10 years from now, to achieve the same objectives, will require additional internal as well as external resource overheads and costs, with reduced productivity due to a sharper ramp-up of skilled labour. The overall costs would be expected to be higher with a delayed approach.

It is estimated that this program, ramping up in 2024, included in the capital budget, is equivalent to an average annual increase of 0.2%/year from 0.05% increasing to a total of 0.38% in 2028 for the average customer.

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 and 02]

01	Enbridge Gas should increase its spending on the Vintage Steel Replacement Program in order to help prepare the system for the future by starting to ramp-up the work in 2024 at an average annual increase of 0.2%/year from 0.05% increasing to a total of 0.38% in 2028.
02	Enbridge Gas should defer proactive replacement of its system that would prepare it for the future – even if this means that the cost will be higher in the future.
98	I don't have an opinion on this
99	Don't know

Comments:

Making Choices

Hydrogen Gas

Enbridge Gas is looking at options to blend more Hydrogen gas into the natural gas it delivers to green the gas supply.

Clean hydrogen gas is derived from surplus clean electrical energy that is converted to hydrogen gas through electrolysis technology. The gas is then blended with traditional natural gas, reducing GHG emissions.

Enbridge Gas is considering investing more in clean hydrogen as a tool for reducing GHG emissions in Ontario to allow for additional hydrogen gas to be blended into the natural gas distribution system. This would mean expanding the pilot project at the power-to-gas (P2G) facility in Markham where hydrogen gas is currently being produced, to deliver hydrogen-blended natural gas to a larger network of customers, expanding the blended gas area from approximately 3,600 to just under 17,000 customers.

Image: Hydrogen gas can be stored in tanks

Additionally, Enbridge Gas intends to launch a feasibility study that assesses the full system's readiness for more hydrogen gas to be included in the system. The costs for these projects for the average customer are estimated as follows:

	2024	2025 and 2026
Annual cost	0.004%	0.005%

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 and 02]

01	Enbridge Gas should implement these plans for hydrogen gas, which will cost the average customer 0.004% in 2024, increasing to 0.005% in 2025 and 2026.
02	Enbridge Gas should not implement these plans related to Hydrogen gas to reduce GHG emissions and keep rates as low as possible
98	I don't have an opinion on this
99	Don't know

Comments:

Making Choices

Innovation and Technology Fund

Enbridge Gas can support the advancement of various new low-carbon or energy efficient technologies that may not be available to consumers today.

While some of this work is already taking place on a small scale, the budget for these types of projects is currently very limited. Additional contributions from customers would allow Enbridge Gas to expand this type of research and development work.

Similar to other jurisdictions, Enbridge Gas is considering an **Innovation and Technology Fund** in order to support the research, development, and the bringing to market of new low-carbon or energy efficient technologies. Where possible, this would be in partnership with other utilities and organizations.

Some options include funding for …

- new research on energy efficiency technologies,
- hydrogen gas,
- renewable natural gas, or
- carbon capture, utilization and sequestration (CCUS). This is the process of capturing carbon dioxide before it enters the atmosphere and either use it as a resource to create products or permanently storing it underground.

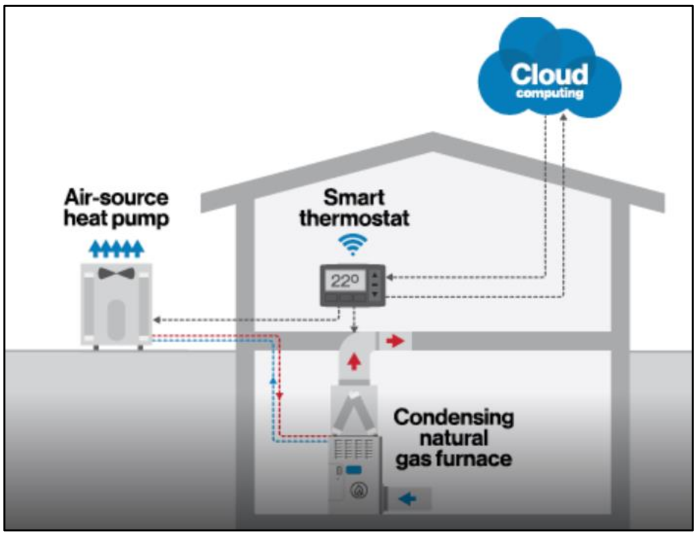


Image: Ontario pilot program tests future of advanced hybrid heating

The more money in this fund, the more projects could be completed, however Enbridge Gas is committed to finding a right balance of spending and planning for the future.

Considering this, which of the following is closest to your view?

[RANDOMIZE 01 THROUGH 03 AND 03 THROUGH 01]

01	Enbridge Gas should develop this fund, spending $1M/year which would cost the average customer 0.003%/year
02	Enbridge Gas should develop this fund, spending $5M/year which would cost the average customer 0.014%/year
03	Enbridge Gas should develop this fund, spending $10M/year which would cost the average customer 0.029%/year
04	Enbridge Gas should **not** develop a fund to invest in new low-carbon or energy efficient technologies
98	I don’t have an opinion on this
99	Don’t know

Comments:

Impact of Choices

Do You Want to Change Your Choices?

So far in this workbook, you have been asked about **4 key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page, you will find the annual bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential annual rate impact for 2024 and 2028 will be re-calculated each time you change one of your answers at the bottom of the page. Costs for 2025-2027 will fall between this range. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Compressor Stations:

Replace one compressor station

- ☐ **Included in the draft plan:** *Within the proposed increase (0.028% in 2024 to 2028)*
- ☐ **Defer as long as possible:** *Though uncertain, at best it would decrease (0.028% in 2024 to 2028)*

Proactive Vintage Steel Pipeline Replacement Program:

Replace 5,100 km of 17,000 km of vintage steel pipeline over the next 20 years

- ☐ **Included in the draft plan:** *Within the proposed increase (0.05% in 2024 to 0.38% in 2028)*
- ☐ **Defer the proactive replacement for as long as possible:** *Decrease by 0.05% in 2024 to 0.38% in 2028*

Hydrogen Gas:

Expand the current pilot project, and complete a system assessment

- ☐ **Add to the draft *plan:*** *0.004% in 2024, no impact in 2028*
- ☐ **No further spending on hydrogen:** *No change in rates*

Innovation and Technology Fund:

Fund research into new low-carbon or energy efficient technologies

- ☐ **Add $1M fund to the plan:** *Increase by 0.003%/year*
- ☐ **Add $5M fund to the plan:** *Increase by 0.014%/year*
- ☐ **Add $10M fund to the plan:** *Increase by 0.029%/year*
- ☐ **No fund:** *No change in rates*

The total impact of your choices would result in a range from:

+/- xx% in 2024 to +/- xx% in 2028

This would be a change from the estimated average increase of 1.4% in 2024 up to 5.9% in 2028 compared to October 2021 to your bill for distribution over the 5-year planning period that starts in 2024.

Note: these areas will be uniquely populated for each individual customer. The bill impacts of their individual responses will be summe and displayed below.

Enbridge Gas will be reviewing its plan based on the feedback you and other customers are sharing now. However, in doing that review, it is important for Enbridge Gas to get a sense of whether the current draft plan is generally acceptable or not. There were some choice options that Enbridge Gas had already included in the draft plan, and others that were not.

As mentioned earlier in the workbook, the Enbridge Gas plan for 2024 to 2028 focused on the following key objectives:

1. Maintaining system safety and reliability
2. Containing costs
3. Harmonizing rates and services
4. Preparing for the future

Currently the plan is estimated to result in an average annual increase of an average of 1.4% over 2024 to 2028 for a total of 5.9% in 2028 compared to October 2021 rates. Along with your feedback on choices included within the plan, Enbridge Gas will consider your feedback on the choices that have not yet been included and update the plan accordingly.

Considering what you know about Enbridge Gas' plans, and the choices you have been making, which of the following best represents your point of view?

- ☐ Enbridge Gas should increase its investments, seeking to accelerate the programs shared in this workbook where possible, even if that means a higher draft increase over the 5-year period.
- ☐ Enbridge Gas should maintain the draft increase to deliver the programs shared in this workbook, focusing on its outlined objectives over the 5-year period.
- ☐ Enbridge Gas should reduce the draft increase, even if that could mean reductions in performance or increase safety or environmental risks over the 5-year period.
- ☐ Other **(please specify)**
- ☐ Don't know

Comments:

Service and Rate Harmonization

In its plan objectives, Enbridge Gas is looking at harmonizing its rates and services to ensure that the offerings are consistent across the entire service area as Enbridge Gas continues its integration activities. These service offerings are intended to address the needs of customers, to provide incremental flexibility where possible, and to be as simple as possible.

In this section we will ask you about some of the service harmonization proposals that Enbridge Gas is considering. The proposals discussed in this section are not yet finalized and your input, along with further work by Enbridge Gas planners, will help shape the final proposals that Enbridge Gas will include in its application to the Ontario Energy Board. We'll cover:

- ✓ **Contract Rate Distribution Services:** firm, interruptible and seasonal distribution services
- ✓ **Direct Purchase Services:** bundled, semi-unbundled and unbundled services

Customer Experience

Service Harmonization: Contract Rate Distribution Services

The next series of questions are about Enbridge Gas' contract rate distribution services.

Enbridge Gas has prepared a video presentation that explains the service proposals it is considering for contract rate distribution services in more detail. Please watch this video before answering the following questions. You may wish to move back and forth between the video and the workbook in a separate browser to answer all the questions.

Not all the questions may be relevant to the services you are currently receiving, in which case you may choose to select "I don't have an opinion on this" in the answer choices.

There are also various comment boxes available where you can provide additional thoughts on the various topics to share with Enbridge Gas. Your feedback is very important, so please take this opportunity to share your thoughts or concerns on the listed proposals.

Link: https://www.enbridgegas.com/business-industrial/commercial-industrial/workbook#draftproposal

Were you able to watch the Contract Rate Distribution video?

- ☐ Yes
- ☐ No

Comments:
If you're experiencing technical difficulties with the video link, please contact marketresearch@enbridge.com for further support.

Firm distribution services

Firm distribution service offers firm deliveries of natural gas to the end use customer every day of the year. This is the most common service.

The table below summarizes the proposed changes to Enbridge Gas' firm distribution service offering.

Customer Type	Rate Zone	Changes to Distribution Services
Firm Service	Union North	✓ Addition of low-load factor firm service ✓ Broader application of high-load factor service ✓ New compliance rules for overrun - automatic increase of contract demand
	EGD	✓ Ability to request authorized overrun of firm services
	Union South	✓ Addition of low-load factor firm service ✓ Addition of high-load factor firm service ✓ New compliance rules for overrun - automatic increase of contract demand

To what extent does the proposed firm distribution service offering meet the needs of your company?

- ☐ Extremely well
- ☐ Very well
- ☐ Somewhat well
- ☐ Not so well
- ☐ Not well at all
- ☐ Don't know

Are there any parts of this proposal that work particularly well for your company? [OPEN]

Customer Experience

Service Harmonization: Contract Rate Distribution Services

Interruptible distribution services

Interruptible distribution service can be added to firm distribution service or can be contracted separately. This service allows Enbridge Gas to issue a notice of interruption that requires an end user to reduce their consumption completely, or to reduce it to the level of firm service they have contracted.

The table below summarizes the proposed changes to Enbridge Gas' interruptible distribution service offering.

Customer Type	Rate Zone	Changes to Distribution Services
Interruptible Service	**Union North**	✓ Retirement of Rate 25 Sales service
	EGD	✓ Change in non-compliance methodology from curtailment credits/overrun charge to a simplified $/GJ charge
	Union South	✓ Removal of 40-day restriction on interruption

To what extent does the <u>proposed interruptible distribution service offering</u> meet the needs of your company?

- ☐ Extremely well
- ☐ Very well
- ☐ Somewhat well
- ☐ Not so well
- ☐ Not well at all
- ☐ Don't know

Are there any parts of this proposal that work particularly well for your company? [OPEN]

Any parts that do not work well for your company? [OPEN]

Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

Customer Experience

Service Harmonization: Contract Rate Distribution Services

Seasonal distribution services

Seasonal distribution service is a form of firm service that provides access to firm deliveries of natural gas in months where Enbridge Gas does not expect to see peak demand on the system. This service is tailored for customers who do not have their peak demands in the winter.

The table below summarizes the proposed changes to Enbridge Gas' seasonal distribution service offering.

Customer Type	Rate Zone	Changes to Distribution Services
Seasonal Service	**Union North**	✓ Addition of seasonal service
	EGD	✓ Reduction in seasonal service parameters in the winter instead of 5% annual consumption allowance ✓ Ability to add seasonal service to a base level of firm service
	Union South	✓ Broader application of the seasonal option

To what extent does the proposed seasonal distribution service offering meet the needs of your company?

- ◻ Extremely well
- ◻ Very well
- ◻ Somewhat well
- ◻ Not so well
- ◻ Not well at all
- ◻ Don't know

Are there any parts of this proposal that work particularly well for your company? [OPEN]

Any parts that do not work well for your company? [OPEN]

Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

Customer Experience

Service Harmonization: Contract Rate Distribution Services

Reduced rates for interruptible distribution service

Customers with interruptible distribution service are required to stop consuming natural gas upon receipt of a **notice of interruption**. Interruption notifications are sent because of constraints on the Enbridge Gas system, generally due to cold weather or maintenance.

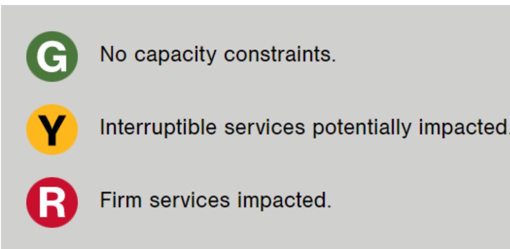


Image: Operational Status information is posted on the Enbridge Gas website

Customers generally comply with interruptions by switching to an alternate fuel source or, in some cases, by stopping their operations during the interruption period. Non-compliance with a notice of interruption results in financial charges to ensure compliance.

Enbridge Gas is studying whether <u>a reduced interruptible rate</u> compared to firm service would result in existing firm, or new, customers converting to interruptible service.

This conversion may result in Enbridge Gas having a reduced or deferred requirement for capital investment to expand the distribution and transmission system. However, the reduced rates for interruptible customers would result in an increase in firm distribution service rates to offset the reduced rates charged to interruptible customers.

Generally, do you support or oppose Enbridge Gas reducing interruptible rates to potentially reduce or defer the requirement for capital investments?

- ☐ Definitely support
- ☐ Somewhat support
- ☐ Somewhat oppose
- ☐ Definitely oppose
- ☐ I don’t have an opinion on this
- ☐ Don’t know

Comments:

Is your company in a position to consider interruptible service if the lower rate provides sufficient benefit?

- ☐ Yes – we already contract interruptible service
- ☐ Yes – we would consider contracting interruptible service
- ☐ No
- ☐ Don’t know

Comments:

Customer Experience

Service Harmonization: Contract Rate Distribution Services

Reduced rates for interruptible distribution service

PN: Do not ask if customer answered NO to question whether they could consider interruptible service (on slide 23)

Based on what you know now, which of the following best reflects your company's situation when it comes to possibly stopping its operations in case of a notice of interruption?

- ☐ Given the nature of our operation, it is not possible to stop operations so we would need to have an alternative fuel system
- ☐ It is possible to stop our operation, but it would make more sense to continue operations with an alternative fuel system
- ☐ It is possible to stop our operations and it likely makes more sense to do so than to invest in an alternative fuel system
- ☐ Don't know

Which of the following statements best reflects your company's situation when it comes to an alternative fuel system?

- ☐ We currently have an alternative fuel system in place that would meet our needs if our natural gas supply is interrupted
- ☐ We currently have an alternative fuel system in place, but it would need to be enhanced to meet our needs if our natural gas supply is interrupted
- ☐ We do not currently have an alternative fuel system in place that would meet our needs if our natural gas supply is interrupted
- ☐ Don't know

If your company currently has an alternative fuel system in place, or if you were to consider one, what type of alternative fuel do you use or are you most likely to use?

Select all that apply.

- ☐ Oil
- ☐ Propane
- ☐ Diesel
- ☐ Biomass
- ☐ Electricity
- ☐ Other ______
- ☐ There are no alternative fuel options available to us
- ☐ Don't know

Comments:

Customer Experience

Service Harmonization: Contract Rate Distribution Services

Reduced rates for interruptible distribution service

PN: Do not ask if customer answered NO to question whether they could consider interruptible service (on slide 23)

Conversion of existing customers from firm to interruptible service may allow Enbridge Gas to provide incremental firm service to the market without capital investment for additional facilities. This may result in increased frequency of interruption for interruptible customers.

If your company elected to take interruptible service, how many days per calendar year would you be able to meet the requirements of a notice of interruption for distribution service?

- ◻ 1-10
- ◻ 11-20
- ◻ 21-30
- ◻ 31-40
- ◻ 41-50
- ◻ 51-60
- ◻ 61+
- ◻ Don’t know

How much of a discount, relative to firm distribution rates, would incent you to convert to interruptible service? Please note that the level of discount is only applicable to the interruptible distribution rate and does not impact the commodity cost (i.e. the cost of the natural gas).

__________%

◻ No level of discount would incent me to convert

◻ Don’t know

Comments:

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

This next series of questions are about Enbridge Gas' direct purchase services.

Enbridge Gas has prepared a video presentation that explains the service proposals it is considering for direct purchase services in more detail. Please watch this video before answering the following questions. You may wish to move back and forth between the video and the workbook in a separate browser to answer all the questions.

Not all the questions may be relevant to the services you are currently receiving, in which case you may choose to select "I don't have an opinion on this" in the answer choices.

There are also various comment boxes available where you can provide additional thoughts on the various topics to share with Enbridge Gas. Your feedback is very important, so please take this opportunity to share your thoughts or concerns on the listed proposals.

Link: https://www.enbridgegas.com/business-industrial/commercial-industrial/workbook#draftproposal

Were you able to watch the Direct Purchase Services video?

- ◻ Yes
- ◻ No

Comments:
If you're experiencing technical difficulties with the video link, please contact marketresearch@enbridge.com for further support.

Utility sale of system gas supply to bundled direct purchase customers

In the Union North rate zones, unlike the other rate zones, Enbridge Gas provides system gas supply to meet the interruptible consumption of bundled DP customers.

Enbridge Gas is considering eliminating the sale of system supply to bundled DP customers in the Union North rate zone. Instead, bundled DP customers would provide their own supply through their DCQ to meet their planned interruptible consumption needs just as they already do to meet their planned firm consumption.

Which of the following comes closest to your view?

- ◻ Enbridge Gas should eliminate the sale of system gas supply for interruptible consumption and direct purchase customers should provide their own gas for all consumption
- ◻ Enbridge Gas should continue to provide system supply should continue to be sold for interruptible consumption in the Union North rate zones
- ◻ I have no opinion on this
- ◻ Don't know

Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Bundled direct purchase gas delivery receipt points

Bundled direct purchase customers currently deliver their gas at the following points:

Rate Zone	Receipt Point
Enbridge Gas Distribution (EGD)	• Empress; or • Dawn; or • Ontario (Enbridge Central Delivery Area (ECDA) or Enbridge Eastern Delivery Area (EEDA)
Union North East	• Dawn (required)
Union North West	• Empress (required)
Union South	• Dawn; and/or • Parkway

When given the choice, customers have been showing a strong preference for delivering their supply at Dawn. Currently:

- 4% of bundled direct purchase gas is delivered at Empress; and
- less than 1% is delivered in the Enbridge EDA

The Enbridge CDA receipt point and Parkway receipt points are in close proximity and Enbridge Gas is considering handling these receipt points similarly.

Enbridge Gas is considering simplifying the administration of the service by moving the small remaining bundled Direct Purchase customers' receipt point obligations from the Empress and Enbridge EDA receipt points to Dawn.

Which of the following comes closest to your view?

- ☐ Enbridge Gas should implement this proposal and move customers' receipt point obligations from Empress and the Enbridge EDA to Dawn
- ☐ Enbridge Gas should not make any changes to the receipt point obligations
- ☐ I have no opinion on this
- ☐ Don't know

Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Bundled direct purchase gas delivery receipt points (cont'd)

Customers obtain their supply and deliver it to meet their contracted DCQ obligation to the receipt point(s) defined in their contract. It is up to the customer where and how they get their supply to that receipt point (delivered service to the receipt point or acquired at some other point and transported to the contracted receipt point(s)).

Enbridge Gas would like to understand if there is significant interest by customers in delivering their gas supply to other points to Enbridge Gas's transmission system. If there is significant interest, Enbridge Gas will evaluate further.

What are your current receipt point(s)? *Please select all that apply.*

- ◻ Dawn
- ◻ Empress
- ◻ Enbridge CDA
- ◻ Enbridge EDA
- ◻ Parkway
- ◻ Don't know

Are there other receipt points to Enbridge Gas' transmission system where you are interested in delivering your gas supply? If so, which ones? *Please select all that apply.*

- ◻ Kirkwall
- ◻ Ojibway
- ◻ Other (please specify) _____
- ◻ Not interested in delivering to any other receipt points
- ◻ Don't know

(PN: If any selected, please ask the following)

How much of your gas supply would you want to shift to these receipt points? If possible, please indicate this in GJ/day.

____

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Bundled direct purchase balancing

Enbridge Gas provides a base level of load balancing to manage differences between *planned* consumption and customer's *contracted DCQ deliveries* for all bundled DP customers. However, across the rate zones, customers have differing responsibilities and control over costs to manage differences from that plan.

Rate Zone	Responsibilities and Options
Enbridge Gas Distribution (EGD)	✓ Balance within a tolerance by the end of contract term ✓ Have access to balancing transactions (some subject to seasonal availability) ✓ Enbridge Gas manages incremental balancing needs, so customers are subject to allocation of the costs of managing these needs
Union North	✓ Not required to balance but may have DCQ deliveries reduced by Enbridge Gas to manage lower than planned consumption ✓ Suite of transactions available throughout the year (some subject to daily operational capability) ✓ Enbridge Gas manages incremental balancing needs, so customers are subject to allocation of the costs of managing these needs
Union South	✓ Balance within a tolerance by the end of contract term ✓ Ensure Banked Gas Account balance is no less than planned by end of February if short (by bringing in more gas), and no greater than planned by end of September if long (by removing gas) ✓ Suite of transactions available throughout the year (some subject to daily operational capability) ✓ Customer has control over the costs of doing so

Enbridge Gas is considering moving to a modified version of the model used in the Union South rate zone today where bundled DP customers manage and control the costs of variances from the planned BGA by balancing, where necessary, on a seasonal basis (and where the modification is to remove the requirement to balance at renewal).

With the adoption of the above, Enbridge Gas is considering offering a common set of cost-based balancing transactions like the Union South rate zone today which will provide a broader suite of transactions with broader availability to allow customers to better manage their gas supply costs.

Which of the following comes closest to your view?

- ☐ Enbridge Gas should implement the modified version of the Union South rate zone model of balancing on a seasonal basis with broader availability of transactions to provide customers more control of their supply and balancing costs
- ☐ Enbridge Gas should implement the EGD rate zone model of balancing only at renewal even though it means that customers will have less control over their supply and balancing costs
- ☐ Enbridge Gas should not make any changes to the current varying load balancing requirements
- ☐ Enbridge Gas should make different changes to the varying load balancing requirements - *please describe:* ________________
- ☐ I have no opinion on this
- ☐ Don't know

Do you have any further thoughts or comments about this proposal that you would like to share?

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Enbridge Gas purchase of bundled direct purchase customer supply during an interruption of distribution service

In the EGD rate zone, unlike the other rate zones, if Enbridge Gas curtails bundled direct purchase customers' interruptible consumption, Enbridge Gas will purchase the proportion of the customers' Mean Daily Volume (MDV) or Daily Contract Quantity (DCQ) that is intended to meet the customer's annual interruptible consumption each day during the distribution interruption period at the average market price for the month of the distribution interruption.

Instead of purchasing the direct purchase customer's gas, **Enbridge Gas is considering adopting the approach used in the Union South rate zone today which is to rely on the customer's contractual obligation to deliver its obligated deliveries and not purchase the customer's gas.** This allows the customer to maintain control over the cost of all its supply costs.

Which of the following comes closest to your view?

- ☐ Enbridge Gas should be able to rely on the delivery obligation and not purchase the direct purchase customer's gas
- ☐ Enbridge Gas should purchase the direct purchase customer's gas at the average market price
- ☐ Enbridge Gas should purchase the direct purchase customer's gas at a different price *(please explain:________)*
- ☐ I have no opinion on this
- ☐ Don't know

Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Semi-unbundled direct purchase gas delivery receipt points

Customers obtain their supply and deliver it to meet their contracted DCQ obligation to the receipt point(s) defined in their contract. It is up to the customer where and how they get their supply to that receipt point (delivered service to the receipt point or acquired at some other point and transported to the contracted receipt point(s)).

Enbridge Gas would like to understand if there is significant interest by customers in delivering their gas supply to other points to Enbridge Gas's transmission system. If there is significant interest, Enbridge Gas will evaluate further.

What are your current receipt point(s)? *Please select all that apply.*

- ☐ Dawn
- ☐ Parkway
- ☐ Don't know

Are there other receipt points to Enbridge Gas' transmission system where you are interested in delivering your gas supply? If so, which ones? *Please select all that apply.*

- ☐ Kirkwall
- ☐ Ojibway
- ☐ Other (please specify) ______
- ☐ Not interested in delivering to any other receipt points
- ☐ Don't know

(PN: If any receipt points selected above, including other, please ask the following)

How much of your gas supply would you want to shift to these receipt points? If possible, please indicate this in GJ/day.

____

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Expansion of the semi-unbundled direct purchase service to bundled DP customers in the Enbridge CDA

In the Union South rate zone, customers have a semi-unbundled DP service available under the current Rate T1 and T2 services. Under this service, customers have obligated deliveries for their gas supply like the bundled DP service and storage has been unbundled from distribution service. Customers can tailor their storage space and storage injection/withdrawal parameters, under OEB approved allocation methods, to meet their reasonable operational needs.

Enbridge Gas is considering expansion of this service beyond the Union South rate zone to bundled customers in areas where the company has the company owned transportation and distribution facilities connected to Enbridge Gas's storage facilities at Dawn [i.e., without the use of transportation facilities owned by third party pipeline companies]. Currently, only bundled customers in the Toronto area of the EGD rate zone meet this requirement.

Which of the following comes closest to your view?

- ◻ Enbridge Gas should expand this service to the Enbridge CDA as described
- ◻ Enbridge Gas should expand this service to other areas and customers even if it means Enbridge Gas needs to contract for additional storage and/or transportation capacity and enhanced services with third parties to be recovered from customers
- ◻ Enbridge Gas should not expand the service
- ◻ I have no opinion on this
- ◻ Don't know

Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Capping semi-unbundled direct purchase storage withdrawal rights

In the Union South rate zone, customers that contract for semi-unbundled service with obligated deliveries can choose an allocation of storage deliverability up to the higher of their DCQ or firm CD – obligated DCQ.

On a peak day in the winter, Enbridge Gas meets contracted peak day needs of its customers with withdrawals from storage generally equivalent to firm CD less obligated DCQ (unless customers have contracted for less). Overall utility peak day deliverability out of storage is approximately 2% of storage space. Through the approved allocation methods, some customers currently receive a significantly higher amount of withdrawal deliverability as a percentage of their contracted storage space. The costs of meeting deliverability is shared by all customers.

Enbridge Gas is considering capping the withdrawal rights resulting from the approved allocation methods to 5% of storage space.

- ✓ This allows from some variability between customer profiles but would reduce the need for Enbridge Gas to purchase deliverability at higher market-based prices and better manage the overall average cost of storage shared by all customers.
- ✓ Most customer allocations are within the 5%.
- ✓ Customers who have their deliverability reduced to 5% would be required to meet their need in excess of the capped amount through additional deliveries of supply in the winter or contracting for market-based deliverability or contracting for an unbundled service or contracting for bundled service.

Which of the following comes closest to your view?

- ◻ Enbridge Gas should implement the withdrawal cap at 5% of storage space
- ◻ Enbridge Gas should implement a withdrawal cap at a different level *(please explain)* ________
- ◻ A withdrawal right cap should not be implemented even though it means additional costs for all customers
- ◻ I have no opinion on this
- ◻ Don't know

Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Utility sale of system gas supply to unbundled (or T-service) direct purchase customers

In the Union North rate zone, unlike the other rate zones, Enbridge Gas provides system gas supply as a source of supply/balancing to meet some of the interruptible consumption of DP customers.

Enbridge Gas is considering the elimination of system supply to meet the needs of unbundled (aka T-service) customers in the Union North rate zone.

- Most of these customers deliver their own gas to the delivery area to meet their interruptible consumption needs and use a Customer Balancing Service (CBS) account (equivalent to 100% of the customer's firm contract demand) to manage daily imbalances between nominated and actual quantities.
- For these customers, the system supply service supplements the CBS and is equivalent to 15% of the customer's firm contract demand.

Since Enbridge Gas does not have firm contracted capacity to support system supply and CBS services, both are subject to the same operational availability.

With an elimination of system gas supply for these customers, Enbridge Gas would:

✓ Provide Union North T-service customers greater thresholds in the CBS on a daily basis equivalent to what had been available under the utility supply service for a total of 115% of firm contract demand

✓ Allow the cumulative balance in the CBS to increase to 150% of firm CD to allow customers time to replace the gas consumed. This provides unbundled DP customers the ability to manage all their gas supply costs.

Which of the following comes closest to your view?

□ Direct purchase customers should provide their own gas for all consumption and the new balancing account tolerances are appropriate

□ Direct purchase customers should provide their own gas for all consumption and the new balancing account tolerances are not appropriate *(please explain)* ________________

□ System supply should continue to be sold for interruptible consumption/balancing in the Union North rate zones

□ I have no opinion on this

□ Don't know

Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Harmonization of CBS, LLB, and DVA used by unbundled (or T-Service) direct purchase customers

Enbridge Gas is considering harmonizing the limits and operation of the CBS used by unbundled (also known as T-service) customers in the Union North rate zone, the Limited Load Balancing (LLB) service used by unbundled customers in the EGD rate zone, and the Daily Variance Account (DVA) used by certain customers in the Union South rate zone. The customer is required to manage the balance in these accounts within certain tolerances which differ by rate zone/service.

These customers have non-obligated gas deliveries to Enbridge Gas and instead nominate their supply each day to meet their planned consumption on the following day. The purpose of these services/accounts is the same - to capture the small differences that occur between the customer's nominated supply and their actual consumption.

Enbridge Gas is considering harmonizing the service with daily limits set at 115% of firm CD and cumulative limits set at 150%. In addition, the service would be subject to interruption based on Enbridge Gas' daily capability.

Which of the following comes closest to your view?

- ☐ Enbridge Gas should harmonize the balancing accounts as described
- ☐ Enbridge Gas should harmonize the balancing accounts but with different limits *(please explain)* ______
- ☐ Each rate zone should continue with its separate balancing service
- ☐ I have no opinion on this
- ☐ Don't know

Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

Customer Experience

Service Harmonization

Those are all our questions about the service harmonization proposals.

Do you have any further thoughts or comments you would like to share about the service harmonization for contract rate or direct purchase proposals discussed in this workbook, in the video, or any other services? [OPEN]

Final Thoughts

Feedback and More About Your Business

Thank you for providing your input into the Enbridge Gas planning process. Your feedback will help ensure we submit a plan that will address our customers' needs and opinions. Before you finish, we would appreciate your answers to two brief topics.

First, to help ensure we continue to improve our customer engagements, we would appreciate your feedback on this workbook. Second, sometimes particular groups of customers have specific needs. We have some questions that will allow us to group your answers with other companies like yours. It should just take one or two more minutes to finish up.

Feedback on Enbridge Gas Customer Engagement

Enbridge Gas values your feedback. This is the first time the utility has conducted a review about its upcoming plans in this type of format.

Thinking about the videos for contract rate distribution services and direct purchase services, please indicate whether you have a favourable or unfavourable impression of those videos.

- ❑ Very favourable
- ❑ Somewhat favourable
- ❑ Somewhat unfavourable
- ❑ Very unfavourable
- ❑ Don't know

Do you have any suggestions for how the videos could be improved in future consultations? [OPEN]

Now thinking about the online workbook, overall, did you have a favourable or unfavourable impression of the workbook you just completed?

- ❑ Very favourable
- ❑ Somewhat favourable
- ❑ Somewhat unfavourable
- ❑ Very unfavourable
- ❑ Don't know

Enbridge Gas indicated that they had a choice of reaching out to customers like you more than once with multiple surveys, or once with a more comprehensive survey that takes longer to complete. Do you feel that Enbridge Gas made the right choice?

- ❑ Yes, one longer survey covering all topics is preferred
- ❑ No, I would have preferred to give feedback through various surveys
- ❑ Don't know

In this workbook, do you feel that Enbridge Gas provided too much information, not enough, or just the right amount?

- ❑ Too little information
- ❑ Just the right amount of information
- ❑ Too much information

More About Your Business

The following questions are for statistical purposes only. This information is used to segment and group similar customers together when the survey results are analysed.

To what extent do you agree or disagree with the following statements?

The cost of my Enbridge Gas bill has a major impact on my business' finances and requires the business do without some other important priorities.

- ❑ Strongly agree
- ❑ Somewhat agree
- ❑ Somewhat disagree
- ❑ Strongly disagree
- ❑ Don't know/No opinion

Customers are well served by the energy system in Ontario.

- ❑ Strongly agree
- ❑ Somewhat agree
- ❑ Somewhat disagree
- ❑ Strongly disagree
- ❑ Don't know/No opinion

How do you use natural gas at your organization? Please check as many as apply.

- ❑ Natural gas is used in production process
- ❑ Natural gas is used as feedstock
- ❑ Natural gas is used for heating or space conditioning
- ❑ Natural gas is used for water heating
- ❑ Other
- ❑ Don't know

Including yourself, how many people work at your organization?

- ❑ 1 person
- ❑ 2 to 5 people
- ❑ 6 to 10 people
- ❑ 11 to 25 people
- ❑ 26 to 50 people
- ❑ More than 50 people
- ❑ Don't know

Approximately, how much was your most recent total Enbridge Gas bill?

$__________

❑ Don't know/not sure

Next Steps

Thank you for your input into our planning process. Enbridge Gas will use the findings from this consultation to ensure that its 2024-2028 plan meets customers' needs, which will be filed to the Ontario Energy Board as part of the Enbridge Gas 2024 Rate Rebasing application in Q4 2022.

Acronyms

Acronym	Meaning
BGA	Banked Gas Account
CBS	Customer Balancing Account
CD	Contract Demand
DCQ	Daily Contract Quantity
DP	Direct Purchase
DVA	Daily Variance Account
ECDA	Enbridge Central Delivery Area
EEDA	Enbridge Eastern Delivery Area
EGD	Enbridge Gas Distribution
GJ	Gigajoule
LLB	Limited Load Balancing
MDV	Mean Daily Volume
RNG	Renewable Natural Gas

ENBRIDGE
Life Takes Energy

Rebasing Customer Engagement Workbook

Transportation Workbook

November 2021

About this Customer Engagement

Welcome to the Enbridge Gas Customer Engagement!

- Enbridge Gas is looking for your feedback to support its investment plan for 2024 and beyond to ensure that plan reflects your needs and preferences.
- You don't need to be a natural gas expert to complete this workbook. It focuses on choices between outcomes that matter to you and provides the background information you need to answer the questions.

If you are completing this workbook online, please note that it will take approximately 20-30 minutes to complete. Your progress will be saved as you move through the workbook, meaning you can leave and return to complete it at any time.

The most important part of this workbook are the survey questions. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and integrate them into their plans. As such, the goal of this workbook is to understand the general priorities and criteria you would like Enbridge Gas to use when making key business decisions. While your view may not always align exactly with any of the options presented, please select the one that is closest. If you truly aren't sure, select the "don't know" option.

If you are reading this on a smaller mobile device, you may wish to access the survey from a tablet, desktop or laptop instead, so that it is easier to read.

Background

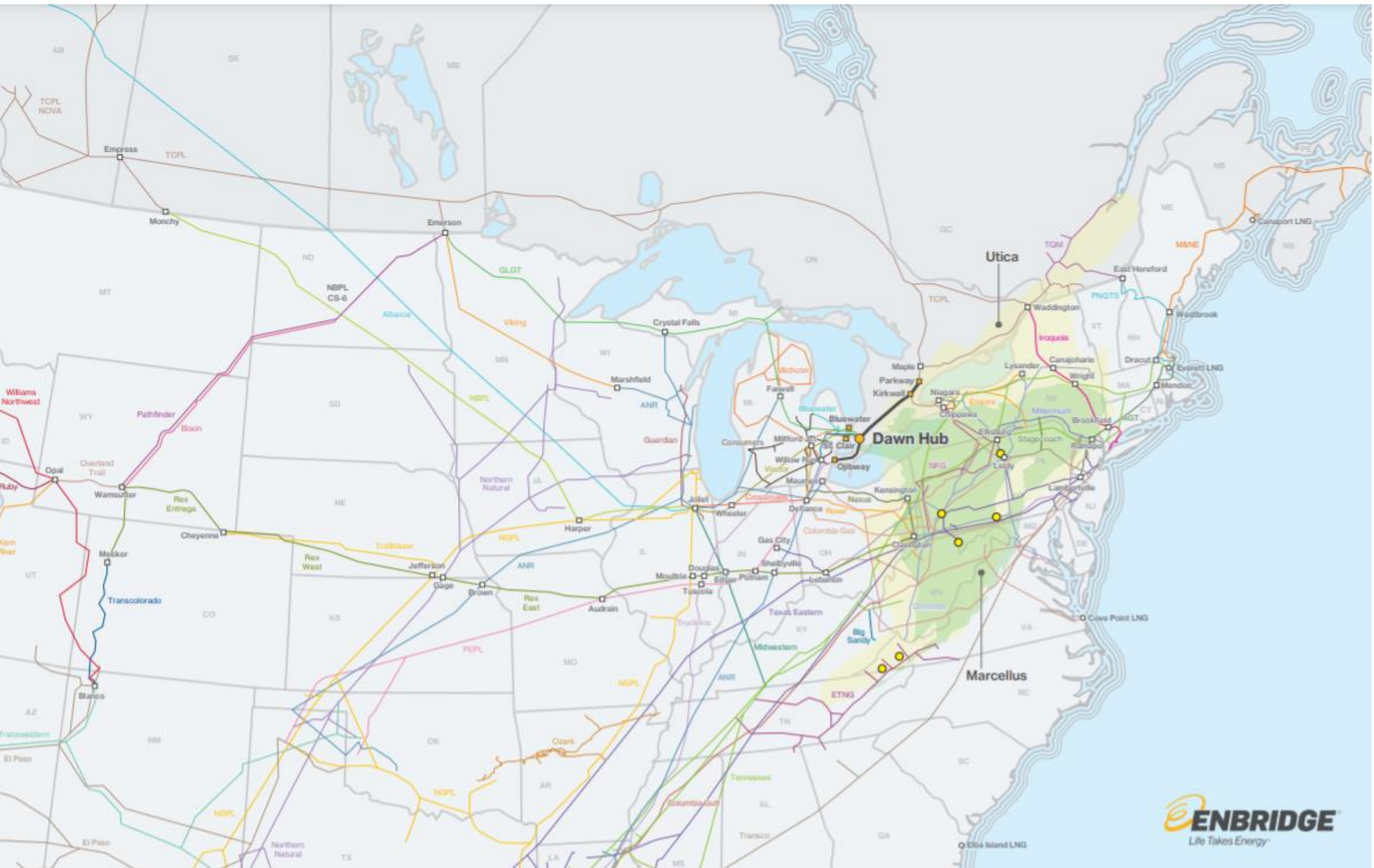
Who is Enbridge Gas?

Enbridge Gas Inc. is based in Ontario and delivers energy to customers in Ontario. Its parent company Enbridge Inc. is headquartered in Calgary, Canada, and operates across North America. All rates and business plans developed by Enbridge Gas must be approved by the Ontario Energy Board (the OEB), which regulates natural gas and electric utilities in Ontario.

Enbridge Gas distributes natural gas to about 3.8 million residential, business and industrial customers, attaching more than 50,000 new customers each year. Enbridge Gas has agreements to provide gas distribution service within 313 municipalities and provides natural gas within 23 First Nation communities across Ontario through a network of over 151,500 kilometers of underground pipeline.

In addition to providing distribution services to customers in our franchise area, Enbridge Gas serves the surrounding storage and transmission marketplace. The Dawn Hub is the largest integrated underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canadian and U.S. supply basins to markets in central Canada, the Great Lakes region and the northeast U.S.

The Dawn-Parkway transmission system is a series of four transmission pipelines (229 km/143 mi), and compressor stations that move natural gas through Ontario from the Dawn Hub near Sarnia, east to the Parkway compressor facility near Mississauga. At Parkway, the system connects with other pipelines that serve residents in the Toronto area, Quebec, eastern Canada and the U.S. northeast.



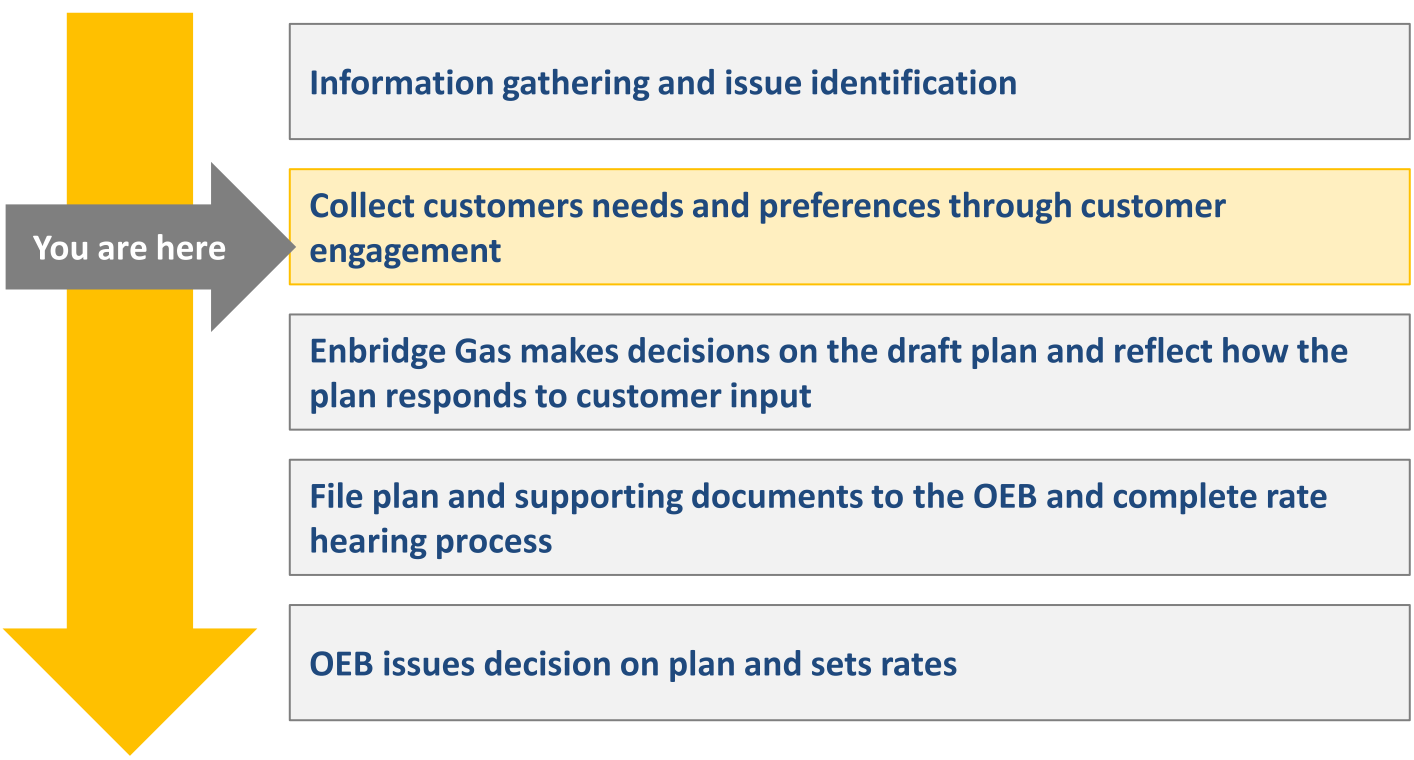
Where does this consultation fit?

Here in Ontario, customer views are central to the utility planning process.

- **All rates and business plans must be approved by the Ontario Energy Board (the OEB).**
- **The OEB requires that utilities consult with customers to understand your views on key trade-offs.**
- **In addition, the utilities must show how they took customer views into account when developing the plan.**

While some planning decisions will depend on detailed knowledge of engineering and industry standards, in other cases the choices will involve trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down. That is where you come in.

The diagram below shows how customers play a role as Enbridge Gas develops and submits its business plan to the Ontario Energy Board.



How well do you feel you understand how your feedback fits within the planning process?

□ Very well □ Somewhat well □ Not very well □ Not at all □ Don’t know

Customer Experience

Customer Outcomes

In considering its investment plan to be implemented starting in 2024, Enbridge Gas must make many decisions. We would like your feedback on the outcomes you would like Enbridge Gas to focus on in its plan. Outcomes are the goals and priorities that matter to you.

There is a list of broad outcomes that Enbridge Gas will need to consider. Using a scale from 0 to 10, where 0 means “not at all important” and 10 means “extremely important”, please tell us how important each one is to you. Be sure to save a rating of 10 for those items that are most important to you.

Outcomes	**Importance Rating (0-10, don’t know)**
Reliably delivering natural gas	
Safely delivering natural gas	
Making good use of the money customers pay	
Providing affordable pricing	
Providing predictable pricing	
Providing dependable customer service	
Minimizing any impacts on the environment	
Being socially responsible	
Supporting the growth of Ontario’s economy	

Are there any other outcomes that are not listed above that are important to you? Please indicate them below:

Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which ones would you rank as first, second and third, in terms of importance to you.

Outcomes	**Ranking, 1^{st}, 2^{nd}, 3^{rd}**
Reliably delivering natural gas	
Safely delivering natural gas	
Making good use of the money customers pay	
Providing affordable pricing	
Providing predictable pricing	
Providing dependable customer service	
Minimizing any impacts on the environment	
Being socially responsible	
Supporting the growth of Ontario’s economy	
Other:	

Customer Experience

Satisfaction and Areas of Improvement

The Ontario Energy Board (OEB) expects Enbridge Gas to develop a plan that will focus on cost effective delivery of outcomes that matter to customers. The following questions will assess your overall experience and satisfaction with Enbridge Gas in meeting your needs.

Overall experience

Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Overall customer service

Taking into consideration all aspects of Enbridge Gas' customer service, how satisfied are you with Enbridge Gas' customer service?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Overall communications

How satisfied are you with the quality of communications you received from Enbridge Gas over the past year?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Customer Experience

Satisfaction and Areas of Improvement

Firm gas transportation is highly reliable

How satisfied are you with the reliability of Enbridge Gas' firm transportation services?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Effectiveness of the pipeline system for nominating, reporting & invoicing

How satisfied are you with Enbridge Gas' systems for nominating, reporting and invoicing?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Effectiveness of operational communications

How would you characterize the frequency of communications from Enbridge Gas about their operations?

□ Too much
□ Just about right
□ Not enough

Comments:

Customer Experience

Satisfaction and Areas of Improvement

Accurate operational information is readily available

How satisfied are you with Enbridge Gas providing your business relevant and accurate operational information?

☐ Very satisfied
☐ Somewhat satisfied
☐ Neither satisfied nor dissatisfied
☐ Somewhat dissatisfied
☐ Very dissatisfied
☐ Don't know

Comments:

Competitive rates and discounts

How satisfied are you that Enbridge Gas' transportation rates and discounts are competitive?

☐ Very satisfied
☐ Somewhat satisfied
☐ Neither satisfied nor dissatisfied
☐ Somewhat dissatisfied
☐ Very dissatisfied
☐ Don't know

Comments:

Account representatives are responsive

How satisfied are you with Enbridge Gas' response time to your inquiries?

☐ Very satisfied
☐ Somewhat satisfied
☐ Neither satisfied nor dissatisfied
☐ Somewhat dissatisfied
☐ Very dissatisfied
☐ Don't know

Comments:

Customer Experience

Satisfaction and Areas of Improvement

Account representatives are readily available

How satisfied are you with the availability of Enbridge Gas' representatives when you reach out to them?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Customer Experience

Transportation Rates

What are the costs?

Enbridge Gas transportation rates are largely driven by Dawn Parkway transmission system and Dawn Station costs. Dawn Parkway transmission costs include transmission pipelines, the compressors and metering equipment along the pipeline including facilities at the Parkway Station. Dawn Station demand costs include the facilities and compressors at the Dawn Station used for transmission purposes.

How are costs included in rates?

The transportation costs are allocated between in-franchise and ex-franchise rate classes based on distance weighted design day demands. The Dawn Station costs are allocated between rate classes based on the use of the Dawn station. The cost allocated to ex-franchise rate classes are recovered through rates based on the use of the transportation services available to customers on the Dawn to Parkway system.

How are rates updated?

Enbridge Gas transportation rates are adjusted using a five-year framework which was approved by the Ontario Energy Board. An annual update includes a formula that adjusts rates each year based on inflation less a productivity factor and approved investments in infrastructure. At the end of the five-year period, Enbridge Gas reviews all of its costs and applies to the Ontario Energy Board for new rates and a new framework to adjust rates going forward. This customer engagement will support plans for the 2024-2028 period.

How well do you understand the basics of how natural gas transportation rates are set?
□ Completely understand □ Somewhat understand □ Do not understand □ Don’t know

Customer Experience

Transportation Rates

Cost Allocation Considerations

Enbridge Gas allocates its costs for providing services to the different rate classes for the purpose of designing rates.

Enbridge Gas' cost allocation practice allocates costs to rate classes based on cost causality principles using specific knowledge of how its system is operated. Although judgment is required in allocating costs, cost allocation results in rate classes that reflect 'user pay' – that is, customers pay in their rate for the cost of the service they use.

How familiar are you with the cost allocation objectives?
□ Very familiar □ Somewhat familiar □ Not very familiar □ Not at all familiar □ Don't know

As a result of significant system growth over the last five years, Enbridge Gas is considering a change to the cost allocation methodology of the Parkway Station costs. As you may be aware, Enbridge Gas has invested substantially in expanding this part of our system and the Parkway Station now represents approximately 20% of the Dawn Parkway transmission costs. The cost allocation change being considered involves allocating the Parkway Station costs to rates that use the Parkway Station rather than including it in the overall costs of the Dawn Parkway system.

The Parkway Station facilities are designed to meet Enbridge Gas' design day requirement to export gas from the Enbridge Gas system into the TransCanada and Enbridge Gas systems through Parkway. They are not necessary to transport or deliver natural gas to other locations along Dawn to Parkway. Allocating Parkway Station demand costs using this user pay methodology will result in an increase of M12 rate class costs by approximately 4%.

Thinking about Enbridge Gas' consideration of the cost allocation change for the Parkway Station, which of the following statements best describes your view?

01	Enbridge Gas should not change the recovery of the Parkway Station and all M12/C1 paths should pay for it based on the use of the Dawn to Parkway system.
02	Enbridge Gas should change the recovery of the Parkway Station costs and recover the costs from only those M12/C1 paths that use the Parkway Station.
98	I don't have an opinion on this
99	Don't know

Are there other ways that Enbridge Gas should consider allocating Parkway Station costs?

Comments:

Customer Experience

Transportation Rates

Rate Design Considerations

Within the M12/C1 rate classes, these questions will examine how costs are allocated by specific paths. In addition to the consideration of possible changes in the cost allocation of the Parkway Station, Enbridge Gas is also considering assigning the costs of the Parkway Station to those M12/C1 paths that use the Parkway Station.

Enbridge Gas' current rate design recovers the costs of the Dawn Parkway transmission costs (including Parkway Station) from each M12/C1 path based on a distance weighted use of the Dawn to Parkway system. Currently, Dawn Station costs are recovered from M12/C1 paths that use Dawn Station only.

This change would mean that the Parkway Station costs would be recovered in a similar manner as the Dawn Station and assigned to the Dawn to Parkway and Kirkwall to Parkway rates but not to the Kirkwall to Dawn rate.

Assigning Parkway Station costs to the M12/C1 paths that use the Parkway Station will result in an increase to the Kirkwall to Parkway rate, a decrease to the Kirkwall to Dawn rate and have very little impact on the Dawn to Parkway rate.

Thinking about Enbridge Gas' consideration of the rate design change for the Parkway Station, which of the following statements best describes your view?

01	Enbridge Gas **should not** change the recovery of the Parkway Station and all M12 paths should pay for it based on the use of the Dawn to Parkway system.
02	Enbridge Gas **should** change the recovery of the Parkway Station costs from those M12 paths that use the Parkway Station.
98	I don't have an opinion on this
99	Don't know

Are there other rate design methodologies that Enbridge Gas should consider?
Comments:

If the Ontario Energy Board approved a rate increase for 2024 and beyond, which of the following statements best describes your view on the implementation of the rate change?

01	Adjust rates to reflect costs as they occur, which may result in more annual volatility
02	Apply a steady annual increase in rates over a 5-year period to minimize annual volatility
03	Apply a larger one time increase in the first rebasing year and then leave rates flat for the remaining period
98	I don't have an opinion on this
99	Don't know

Comments:

Energy Transition

Enbridge Gas is also looking at ways in which it can support its organizational, as well as federal and provincial goals to reduce greenhouse gas (GHG) emissions and achieve net zero targets.

- **Enbridge Inc. targets to reduce, from its operations, GHG emission intensity by 35% by 2030 over 2018 levels, and to reach Net Zero GHG emissions by 2050**
- **Federal targets to reduce GHG emissions by 40-45% by 2030 over 2005 levels and to reach Net Zero GHG emissions by 2050**
- **Provincial target to reduce GHG emissions by 30% by 2030 over 2005 levels**

There are several options that Enbridge Gas is considering in its efforts to minimize impact on the environment, which include reducing the demand for natural gas, greening the gas through the blending of Renewable Natural Gas (RNG) or Hydrogen Gas with traditional natural gas, and supporting the development of new technologies and options that may not exist today.

Thinking about your organization's goals, as well as broader climate targets, what are some ways in which Enbridge Gas can support these goals and targets?
Comments:

Final Thoughts

Feedback on Enbridge Gas Customer Engagement

Enbridge Gas values your feedback. This is the first time the utility has conducted a review about its upcoming plans in this type of format.

Overall, did you have a favourable or unfavourable impression of the workbook you just completed?

- ❑ Very favourable
- ❑ Somewhat favourable
- ❑ Somewhat unfavourable
- ❑ Very unfavourable
- ❑ Don't know

In this workbook, do you feel that Enbridge Gas provided too much information, not enough, or just the right amount?

- ❑ Too little information
- ❑ Just the right amount of information
- ❑ Too much information

Was there any content missing that you would have liked to have seen included in this workbook?

- ❑ None

Is there anything that you would still like answered?

- ❑ None

Would you like to be notified by email about how Enbridge Gas used your feedback?

- ❑ Yes
- ❑ No

[IF "Yes"] Please enter you preferred email address:

____

Next Steps

Thank you for your input into our planning process.

After this, Enbridge Gas will use the findings from this consultation to ensure that its 2024-2028 plan meets customers' needs, which will be filed to the Ontario Energy Board as part of the Enbridge Gas 2024 Rate Rebasing application in Q4 2022.

ENBRIDGE
Life Takes Energy

Rebasing Customer Engagement
Workbook

Producer (M13) Workbook

November 2021

About this Customer Engagement

Welcome to the Enbridge Gas Customer Engagement!

- Enbridge Gas is looking for your feedback to support its investment plan for 2024 and beyond to ensure that plan reflects your needs and preferences.
- You don't need to be a natural gas expert to complete this workbook. It focuses on choices between outcomes that matter to you and provides the background information you need to answer the questions.

If you are completing this workbook online, please note that it will take approximately 20-30 minutes to complete. Your progress will be saved as you move through the workbook, meaning you can leave and return to complete it at any time.

The most important part of this workbook are the survey questions. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and integrate them into their plans. As such, the goal of this workbook is to understand the general priorities and criteria you would like Enbridge Gas to use when making key business decisions. While your view may not always align exactly with any of the options presented, please select the one that is closest. If you truly aren't sure, select the "don't know" option.

If you are reading this on a smaller mobile device, you may wish to access the survey from a tablet, desktop or laptop instead, so that it is easier to read.

Background

Who is Enbridge Gas?

Enbridge Gas Inc. is based in Ontario and delivers energy to customers in Ontario. Its parent company Enbridge Inc. is headquartered in Calgary, Canada, and operates across North America. Rates and business plans developed by Enbridge Gas must be approved by the Ontario Energy Board (the OEB), which regulates natural gas utilities in Ontario.

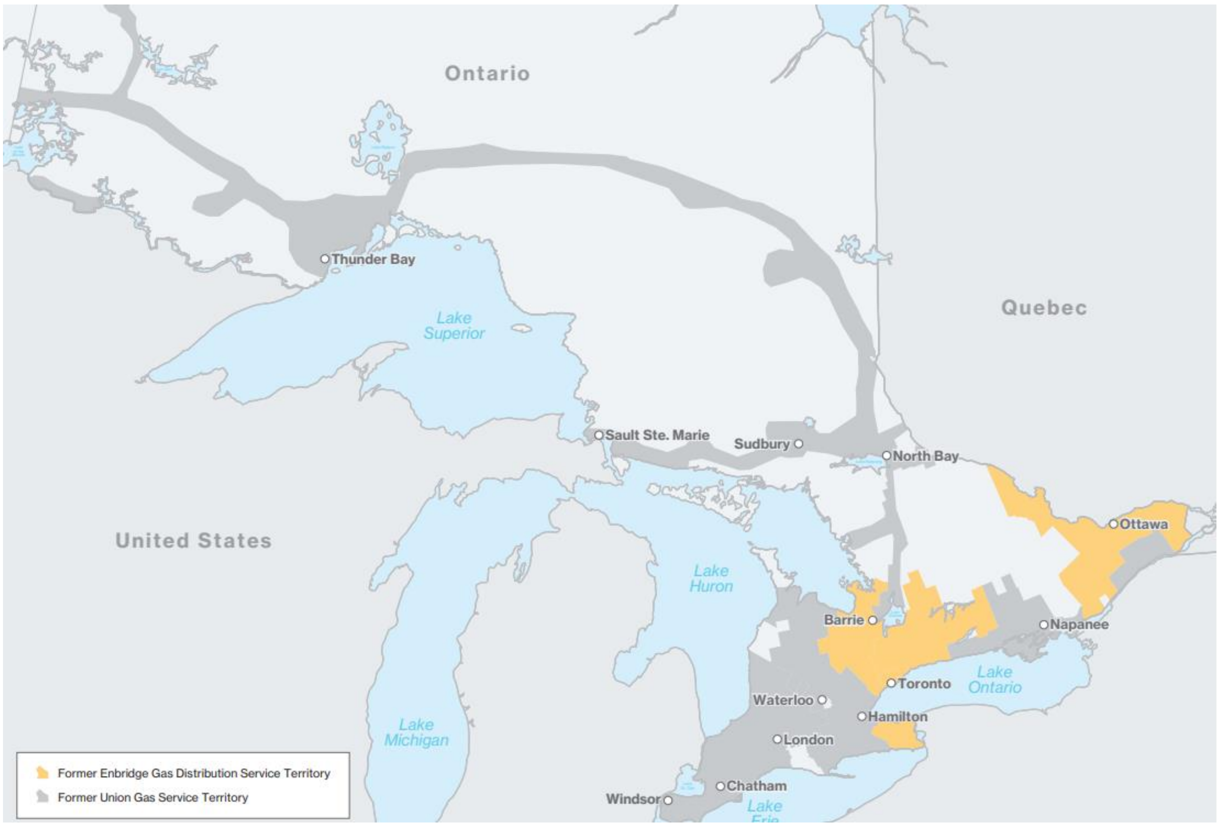
Enbridge Gas …

- ✓ Distributes natural gas to about 3.8 million residential, business and industrial customers
- ✓ Attaches more than 50,000 new customers each year
- ✓ Has agreements to provide gas distribution service within 313 municipalities and provides natural gas within 23 First Nation communities
- ✓ Has a network of over 151,500 kilometers of underground pipeline

In 2019, Enbridge Gas Distribution and Union Gas merged to form one company, Enbridge Gas Inc. Throughout this workbook we occasionally refer to Legacy Enbridge Gas Distribution and Legacy Union Gas (the previous companies), but mainly refer to the whole service area or territory that Enbridge Gas serves today.

In addition to providing distribution services to customers in our franchise area, Enbridge Gas serves the surrounding storage and transmission marketplace. The Dawn Hub is the largest integrated underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canadian and U.S. supply basins to markets in central Canada, the Great Lakes region and the northeast U.S.

The Dawn-Parkway transmission system is a series of four transmission pipelines (229 km/143 mi), and compressor stations that move natural gas through Ontario from the Dawn Hub near Sarnia, east to the Parkway compressor facility near Mississauga. At Parkway, the system connects with other pipelines that serve residents in the Toronto area, Quebec, eastern Canada and the U.S. northeast.



Where does this consultation fit?

Here in Ontario, customer views are central to the utility planning process.

- **All rates and business plans must be approved by the Ontario Energy Board (the OEB).**
- **The OEB requires that utilities consult with customers to understand your views on key trade-offs.**
- **In addition, the utilities must show how they took customer views into account when developing the plan.**

While some planning decisions will depend on detailed knowledge of engineering and industry standards, in other cases the choices will involve trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down. That is where you come in.

The diagram below shows how customers play a role as Enbridge Gas develops and submits its business plan to the Ontario Energy Board.

Information gathering and issue identification

You are here → **Collect customers needs and preferences through customer engagement**

Enbridge Gas makes decisions on the draft plan and reflect how the plan responds to customer input

File plan and supporting documents to the OEB and complete rate hearing process

OEB issues decision on plan and sets rates

How well do you feel you understand how your feedback fits within the planning process?

☐ Very well ☐ Somewhat well ☐ Not very well ☐ Not at all ☐ Don’t know

Customer Experience

Customer Outcomes

In considering its investment plan to be implemented starting in 2024, Enbridge Gas must make many decisions. We would like your feedback on the outcomes you would like Enbridge Gas to focus on in its plan. Outcomes are the goals and priorities that matter to you.

There is a list of broad outcomes that Enbridge Gas will need to consider. Using a scale from 0 to 10, where 0 means "not at all important" and 10 means "extremely important", please tell us how important each one is to you. Be sure to save a rating of 10 for those items that are most important to you.

Outcomes	**Importance Rating (0-10, don't know)**
Reliably delivering natural gas	
Safely delivering natural gas	
Making good use of the money customers pay	
Providing affordable pricing	
Providing predictable pricing	
Providing dependable customer service	
Minimizing any impacts on the environment	
Being socially responsible	
Supporting the growth of Ontario's economy	

Are there any other outcomes that are not listed above that are important to you?

Please indicate them below:

Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which ones would you rank as first, second and third, in terms of importance to you.

Outcomes	**Ranking, 1st, 2nd, 3rd**
Reliably delivering natural gas	
Safely delivering natural gas	
Making good use of the money customers pay	
Providing affordable pricing	
Providing predictable pricing	
Providing dependable customer service	
Minimizing any impacts on the environment	
Being socially responsible	
Supporting the growth of Ontario's economy	
Other:	

Customer Experience

Satisfaction and Areas of Improvement

The Ontario Energy Board (OEB) expects Enbridge Gas to develop a plan that will focus on cost effective delivery of outcomes that matter to customers. The following questions will assess your overall experience and satisfaction with Enbridge Gas in meeting your needs.

Overall experience

Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Overall customer service

Taking into consideration all aspects of Enbridge Gas' customer service, how satisfied are you with Enbridge Gas' customer service?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Overall communications

How satisfied are you with the quality of communications you received from Enbridge Gas over the past year?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Customer Experience

Satisfaction and Areas of Improvement

Effectiveness of the pipeline system for nominating, reporting & invoicing

How satisfied are you with Enbridge Gas' systems for nominating, reporting and invoicing?

□ Very satisfied

□ Somewhat satisfied

□ Neither satisfied nor dissatisfied

□ Somewhat dissatisfied

□ Very dissatisfied

□ Don't know

Comments:

Effectiveness of operational communications

How would you characterize the frequency of communications from Enbridge Gas about their operations?

□ Too much

□ Just about right

□ Not enough

Comments:

Customer Experience

Satisfaction and Areas of Improvement

Accurate operational information is readily available

How satisfied are you with Enbridge Gas providing your business relevant and accurate operational information?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Account representatives are responsive

How satisfied are you with Enbridge Gas' response time to your inquiries?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Account representatives are readily available

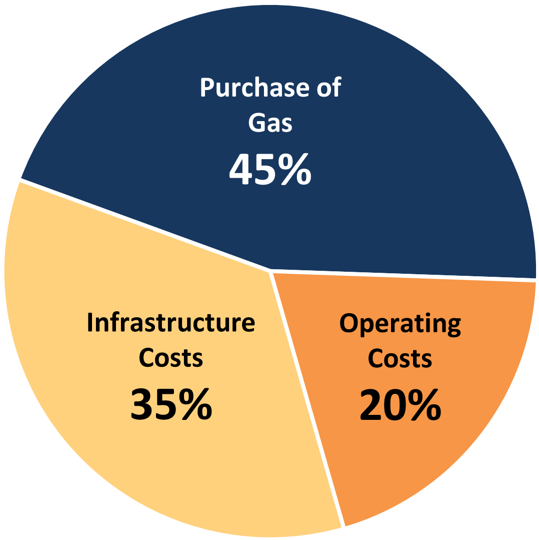
How satisfied are you with the availability of Enbridge Gas' representatives when you reach out to them?

□ Very satisfied
□ Somewhat satisfied
□ Neither satisfied nor dissatisfied
□ Somewhat dissatisfied
□ Very dissatisfied
□ Don't know

Comments:

Customer Experience

Rates



What are the costs?
The proportions of Enbridge Gas' expenditures are shown in the pie chart.

- ✓ The **Purchase of Gas** shows the 'passed through' costs that pay for the natural gas and transportation to the Enbridge Gas system.
- ✓ The **Infrastructure Costs** pay the capital costs of the infrastructure (such as pipes, compressors, buildings and other equipment) used to move and store natural gas across the system.
- ✓ The **Operating Costs** pay for operations – including the people who operate and maintain the equipment and the people who provide customer service.

These costs will be reviewed in detail through the application to the OEB.

Cost Allocation Considerations

Enbridge Gas allocates its costs for providing services to the different rate classes for the purpose of designing rates.

Enbridge Gas' cost allocation practice allocates costs to rate classes based on cost causality principles using specific knowledge of how its system is operated. Although judgment is required in allocating costs, cost allocation results in rate classes that reflect 'user pay' – that is, customers pay in their rate for the cost of the service they use.

How familiar are you with the cost allocation objectives?
□ Very familiar □ Somewhat familiar □ Not very familiar □ Not at all familiar □ Don't know

How are rates updated?

Enbridge Gas rates are adjusted using a five-year framework which was approved by the Ontario Energy Board. An annual update includes a formula that adjusts rates each year based on inflation less a productivity factor and approved investments in infrastructure. At the end of the five-year period, Enbridge Gas reviews all of its costs and applies to the Ontario Energy Board for new rates and a new framework to adjust rates going forward. This customer engagement will support plans for the 2024-2028 period.

How well do you understand the basics of how natural gas rates are set?
□ Completely understand □ Somewhat understand □ Do not understand □ Don't know

Comments:

Rates

Cost of New Facilities

When a producer asks for a new attachment to the Enbridge Gas system, estimates for both the capital costs required for attachment along with the future revenue stream that will be received by Enbridge Gas from signing a contract with the producer are performed.

If the estimated revenues are insufficient to cover the capital costs, Enbridge Gas requires the producer to pay for the difference. Depending on the rate zone that the producer is in, the recovery of this capital cost occurs as follows:

For the Enbridge Gas Distribution Rate Zone: If the producer passes the Enbridge Gas capital requirements, they have the option to pay the capital shortfall over the term of the agreement signed by the producer. If the producer doesn't pass the credit requirements or chooses not to pay the shortfall over the term of the agreement, they have the option to pay the shortfall in an upfront lump-sum amount.

For the Union Rate Zone: The producer is required to pay half of the shortfall prior to procurement of construction materials with the balance to be paid in full prior to construction starting.

For both rate zones, a true-up based on actual costs incurred is performed after construction has been completed.

Enbridge Gas is considering alternatives to the payment of shortfall amounts that would be consistent regardless of which rate zone the producer is in.

Thinking about Enbridge Gas' consideration of the treatment of Contribution in Aid of Construction (CIAC) payments, which of the following statements best describes your view?

	Enbridge Gas should require the full shortfall payment from producers prior to the facilities being constructed
	Enbridge Gas should offer producers the option to pay for the shortfall over the term of the agreement, subject to the producer meeting Enbridge Gas credit requirements
	The producer should have the option to choose from either option, subject to meeting Enbridge Gas credit requirements
	I don't have an opinion on this
	Don't know

Comments:

Customer Experience

Rates

Options For The Sale of Production

Enbridge Gas is considering three (3) different elections that a producer can make to sell their production.

1) **Transport the production to the Enbridge Gas Dawn Hub and sell to market participants** (marketers or direct purchase customers of Enbridge Gas). This option would require the producer to nominate the transportation from the meter location to Dawn daily.
2) If the producer is also an Enbridge Gas direct purchase customer, the **production can be used to meet the customer's direct purchase obligations**. The molecule would be transferred by the producer to their direct purchase obligated delivery point and transferred to the direct purchase account. Normal direct purchase rules would still apply once the molecule is delivered.
3) The producer would **sell to Enbridge Gas' Gas Supply** group. The sale would be deemed to occur at Dawn and would be a firm service. The producer would not be required to nominate the service and the payment would be based on actual production during the month.

Enbridge Gas is currently proposing that the producer makes an election for one of the three choices at the time of contract execution.

Thinking about Enbridge Gas' options proposed for the sale of production, do you support or oppose these options?

□ Strongly support

□ Somewhat support

□ Somewhat oppose

□ Strongly oppose

□ Don't know

Comments:

Thinking about Enbridge Gas' proposal that the producer make a choice of how they want to sell their production at the time they sign their agreement, which of the following statements best describes your view?

	The producer should have the ability to change their election annually
	A producer should have the ability to choose more than one option at a time
	I don't have an opinion on this
	Don't know

Are there any other options that Enbridge Gas should consider for producers to sell their production?

Comments:

Energy Transition

Enbridge Gas is also looking at ways in which it can support its organizational, as well as federal and provincial goals to reduce greenhouse gas (GHG) emissions and achieve net zero targets.

- **Enbridge Inc. targets to reduce, from its operations, GHG emission intensity by 35% by 2030 over 2018 levels, and to reach Net Zero GHG emissions by 2050**
- **Federal targets to reduce GHG emissions by 40-45% by 2030 over 2005 levels and to reach Net Zero GHG emissions by 2050**
- **Provincial target to reduce GHG emissions by 30% by 2030 over 2005 levels**

There are several options that Enbridge Gas is considering in its efforts to minimize impact on the environment, which include reducing the demand for natural gas, greening the gas through the blending of Renewable Natural Gas (RNG) or Hydrogen Gas with traditional natural gas, and supporting the development of new technologies and options that may not exist today.

Thinking about your organization's goals, as well as broader climate targets, what are some ways in which Enbridge Gas can support these goals and targets?
Comments:

Final Thoughts

Feedback on Enbridge Gas Customer Engagement

Enbridge Gas values your feedback. This is the first time the utility has conducted a review about its upcoming plans in this type of format.

Overall, did you have a favourable or unfavourable impression of the workbook you just completed?

- ❑ Very favourable
- ❑ Somewhat favourable
- ❑ Somewhat unfavourable
- ❑ Very unfavourable
- ❑ Don’t know

In this workbook, do you feel that Enbridge Gas provided too much information, not enough, or just the right amount?

- ❑ Too little information
- ❑ Just the right amount of information
- ❑ Too much information

Was there any content missing that you would have liked to have seen included in this workbook?

- ❑ None

Is there anything that you would still like answered?

- ❑ None

Would you like to be notified by email about how Enbridge Gas used your feedback?

- ❑ Yes
- ❑ No

[IF “Yes”] Please enter you preferred email address:

____

Next Steps

Thank you for your input into our planning process.

After this, Enbridge Gas will use the findings from this consultation to ensure that its 2024-2028 plan meets customers' needs, which will be filed to the Ontario Energy Board as part of the Enbridge Gas 2024 Rate Rebasing application in Q4 2022.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Three Fires Group Inc. (Three Fires)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1

Preamble:

Enbridge Gas Inc. ("**Enbridge**") describes the customer engagement process that it conducted in 2021 and 2022, which involved over 12,000 customers. The process consisted of three phases and included various forms of engagement, such as focus groups, in-depth interviews, telephone surveys, and online workbooks.

Question(s):

a) Please produce Enbridge's 2022 *Indigenous Reconciliation Action Plan* ("**IRAP**") and *Indigenous Peoples Policy* ("**IPP**").

b) Please describe how Enbridge has applied the principles, policies and commitments set out in its IRAP and IPP in the context of the current Application.

c) Please provide specific comment on how the following items from the IPP apply in the context of the current Application:

- Enbridge's stated principle to "engage early and sincerely through processes that aim to achieve the support and agreement of Indigenous nations and governments for our projects and operations that may occur on their traditional lands" (IPP at page 2);

- Enbridge's stated principle that it seeks "the input and knowledge of Indigenous groups to identify and develop appropriate measures to avoid and/or mitigate the impacts of our projects and operations that may occur on their traditional lands." (IPP at page 2);

- Enbridge's statement that it will "provide ongoing leadership and resources to ensure the effective implementation of the above principles, including the development of implementation strategies and specific action plans…" (IPP at page 3).

d) Please provide specific comment on how the following items from the IRAP apply in the context of the current Application:

- Pillar 2 concerning community engagement and relationships;
- Pillar 3 concerning economic inclusion and partnerships;
- Pillar 5 and in particular its objectives relating to sustainability;
- Pillar 6 concerning governance and leadership.

e) Please produce any additional internal or public documents that set out any Enbridge policies applicable to Enbridge's interactions with Indigenous customers or groups for the purposes of the matters at issue in this Application.

f) Please describe how Enbridge worked to ensure representation for all types of customers in all rate zones, as stated at paragraph 7 of Karen Sweet's evidence, including specific comment with respect to Indigenous customers.

g) Please describe any efforts taken on the part of Enbridge to ensure Indigenous engagement generally, or participation in consultations specifically, in a form relevant to this Application.

h) Please describe any efforts taken on the part of Innovative Research Group to ensure Indigenous participation in their consultations.

i) What are the costs incurred to date and what are the anticipated costs to the ratepayers for operationalizing the IRAP in Enbridge's Ontario franchise areas? In your answer, please provide the following:

1. A general answer for both past and future anticipated costs
2. A breakdown for both costs already incurred by franchise area
3. Detailed annual projections of anticipated costs by franchise area for the next 5 years

j) What are the costs incurred to date and what are the anticipated costs to the ratepayers for operationalizing the IPP in Enbridge's Ontario franchise areas? In your answer, please provide the following:

1. A general answer for both past and future anticipated costs
2. A breakdown for both costs already incurred by franchise area
3. Detailed annual projections of anticipated costs by franchise area for the next 5 years

k) Please describe Enbridge's plans to apply the IRAP to enable Indigenous ownership and operation of Enbridge's infrastructure. In particular, what are its plans to work with Indigenous communities, not only in stewarding the environment, but also in owning and operating critical energy infrastructure?

l) Please describe how the IRAP applies to current and future regulated and unregulated RNG assets and provide specific comment with respect to Indigenous ownership and operation of these assets.

Response:

a) Please see Attachment 1 for the IRAP, and Attachment 2 for the IPP.

b) Enbridge Inc.'s Indigenous Peoples Policy (IPP) directs the methods by which Enbridge develops mutually beneficial relations with Indigenous communities close to, or potentially affected by, our operations. This Application does not have a physical impact on traditional lands or on Aboriginal and treaty rights and therefore, Enbridge Gas has not undertaken a consultation program commensurate with what would be undertaken in relation to an application for facilities that may have a potential impact on Aboriginal and treaty rights. Nevertheless, the overarching principles in the IPP, including the recognition of the importance of reconciliation between Indigenous peoples and broader society, will continue to guide Enbridge Gas's interactions with Indigenous communities and peoples.

   Akin to ESG goals, the IRAP is not a document that is intended to be directly applied to regulatory applications. The IRAP serves as a corporate roadmap for Enbridge Inc.'s continued journey towards truth and reconciliation. It is the mechanism by which Enbridge Inc., as a company, will remain accountable for executing on our commitments and to our partners, including Indigenous peoples. Enbridge Inc. will be publicly reporting on its progress against the commitments set out in the IRAP starting with its 2023 Sustainability Report.

c) Please see response at part b).

d) Please see response at part b).

e) Please see response at part a) and b). There are no additional documents to provide.

f) To ensure the results are representative of all customers, customer engagement sample lists were randomly pulled from the Enbridge Gas systems. Responses were reviewed and weighted according to sample proportions as explained in detail in the Sample Design sections of the report (Exhibit 1, Schedule 6, Tab 1, Attachment 1, pages 108 to 113, 162 to 163, 225 to 226 and 307). Enbridge Gas made just a few minor exclusions, such as customers who previously requested not to be included in market research and customers who didn't meet basic screening criteria such as being age 18 or older (as indicated in the survey instruments). As described in the response at Exhibit I.1.6-GFN-4, Attachment 1, customers with US phone numbers were also removed from lists. Due to this approach, Indigenous customers were included in the samples and results, as confirmed in the Phase Three results, described by Innovative in the response to h).

g) Please see response at part f).

h) The following response was provided by Innovative Research Group:

   This engagement was focused broadly on representing Enbridge Gas ratepayers. The Phase Three workbook did ask about Indigenous identity. Page 228 (of Exhibit 1, Tab 6, Schedule 1, Attachment 1) includes a chart reporting that 2% of the residential workbook sample identified themselves as an Indigenous person.

i) As a corporate roadmap, all existing corporate and Enbridge Gas resources are guided by the IRAP and to the extent their duties can support meeting the goals and targets set by the IRAP, they are involved in its operationalization. As a result, Enbridge Gas does not have the specific breakdown requested.

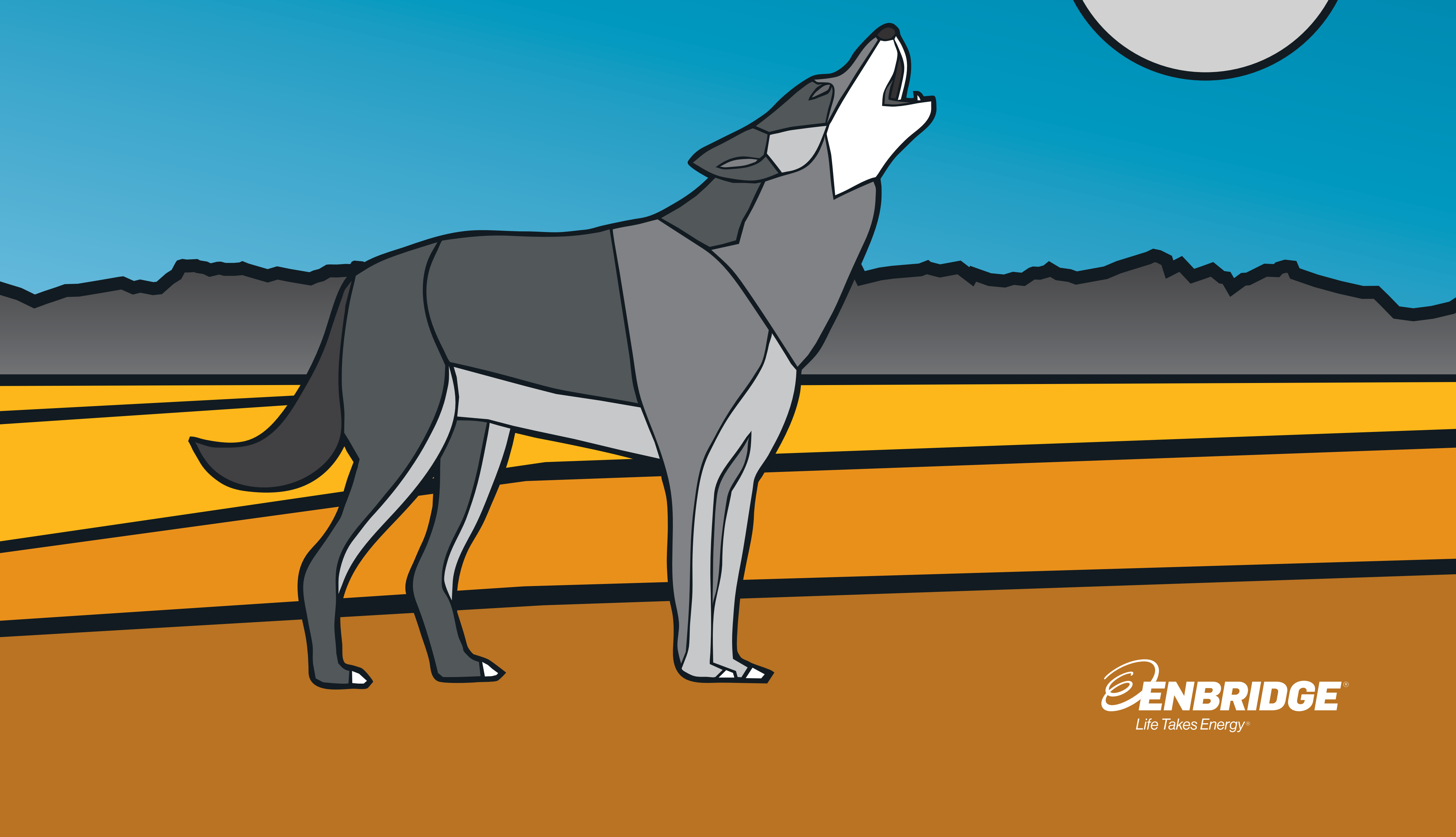
j) Please see response at part i), which statements also apply to the IPP.

k) Please see response at part b). In addition, Enbridge Gas can confirm that it meets with and discusses the interests and priorities of Indigenous groups, including representatives of TFG, to explore, among other things, opportunities to advance innovative partnerships and economic inclusion. While some Indigenous equity partnerships have recently been developed by Enbridge Gas's affiliated companies, those transactions are very complex and specific to the circumstances surrounding those projects and are outside the scope of this Application. For its evidence in support of this Application, and specifically for its proposed 2024 revenue requirement, Enbridge Gas has not included expenses for Indigenous ownership and operation of regulated assets.

l) Please see response at part b). In addition, Enbridge Gas follows the same general approach to Indigenous engagement for RNG-related projects as it does for facilities projects where the duty to consult is triggered. In those cases, Enbridge Gas engages with potentially affected Indigenous groups to avoid or mitigate any impacts the project may have on their rights and interests. Enbridge Gas has not contemplated Indigenous ownership or operation of regulated RNG assets for the purposes of the proposed 2024 revenue requirement. Any unregulated RNG projects are outside the scope of this Application.

The journey ahead

2022 Indigenous Reconciliation Action Plan



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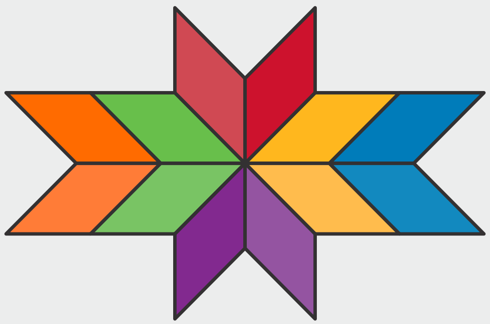


Over the years, Enbridge has been honored with blankets gifted from Indigenous groups. The blankets served as a source of inspiration for the design of the 2022 Indigenous Update Report and this star graphic. We honor these gifts and their importance to the fabric of our culture, and our dedication to continued learning and inclusion of Indigenous culture, heritage and teachings in our everyday lives.

Table of contents

Why an Indigenous Reconciliation Action Plan?

Enbridge is proud to share this Indigenous Reconciliation Action Plan (IRAP). As a North American company, it is important to foster meaningful reconciliation within communities where we live and work. This IRAP continues our long-held commitment to advancing reconciliation with Indigenous peoples. Further, it is developed in recognition of the Truth and Reconciliation Commission's Call to Action #92, the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP), and with respect for and acknowledgement of Indigenous rights and title, treaties, and sovereignty across Turtle Island[1]. Our IRAP will serve as the roadmap by which we will continue our journey to advance truth and reconciliation. It is the mechanism by which we will remain accountable for executing on our commitments and to our partners, including Indigenous peoples.

* All dollar amounts are in CAD except when specified in USD.

[1] The continent of North America is often referred to as Turtle Island by some Indigenous peoples. Both terms appear within this IRAP, where appropriate.

ENBRIDGE
Life Takes Energy

Land acknowledgment

Our projects and operations span Treaty and Tribal lands, the National Métis Homeland, unceded lands and the traditional territories of Indigenous Nations, Tribes, Governments and Groups (Indigenous groups)[2] across North America.

[2] In this IRAP we are using the term "Indigenous groups" when referring to Indigenous nations, governments or groups in Canada and/or Native American Tribes and Tribal associations in the United States. We have the utmost respect for the unique rights and individual names of Indigenous groups across Turtle Island. This collective term is used solely for the purpose of the readability of the IRAP.

About the artist

Jason Carter is an Indigenous sculptor, painter, illustrator and public artist from the Little Red River Cree Nation at John D'Or Prairie, Alberta, and a Distinguished Alumni of MacEwan University. Jason has major permanent installations in both the Calgary and Edmonton International Airports, and his sculpture and canvas artwork are displayed in many public places (NAC, AFA, YWCA Calgary and Edmonton, Travel Alberta, Wood Buffalo Region, Stantec, Banff Caribou Properties, Microsoft and Canada Goose) and private collections globally.

In 2019, Jason was commissioned by the Museum of Aboriginal Peoples' Art and Artifacts of Canada to create three paintings (two 79" x 29" and one 58" x 29") to be permanently installed in the museum's entrance. Jason is the lead sculpture artist for 'In Search of Christmas Spirit'; an immersive sculpture exhibit in Banff, Alberta where he created 12′ to 18′ tall sculptures of bears, wolves, and bison lit from within like a lantern. He worked alongside Banff & Lake Louise Tourism and Parks Canada to complete this initiative. In 2021, Jason created wâpos; another large-scale sculpture installation celebrating the rabbit in Churchill Square, and Winter Solstice, which brought to light the importance of solstice and the passing of the sun and moon in Winter to Indigenous peoples. Most recently, Jason was commissioned by Hockey Canada to hand paint 150 hockey sticks gifted to the player of the game at the World Junior Championships in August 2022.

About Enbridge

Enbridge is a leading North American energy infrastructure company, headquartered on Treaty 7 territory and a portion of the Métis Homeland in Calgary, Canada. We operate locally, living and working in the communities near our projects and operations. Enbridge has additional major offices across Turtle Island in Houston, Edmonton, Toronto, Duluth and Chatham.

We safely and reliably connect millions of people to the energy they rely on every day, fueling quality of life through our North American natural gas, oil, or renewable power networks and our growing European offshore wind portfolio. We continue to invest in modern energy delivery infrastructure and are committed to reducing the carbon footprint of the energy we deliver. Our goal is to achieve net-zero greenhouse gas emissions by 2050.

To learn more, visit us at Enbridge.com.

“We believe that our business can play a critical role in advancing reconciliation, and that means acknowledging the truth and learning from the complicated and challenging history of Indigenous peoples. We need to understand the past in order to move forward.

We are a values-driven organization, and therefore we recognize the deep and meaningful connections that Indigenous nations have to water, land and the environment. We've learned not to walk into Indigenous communities with all the answers, but rather to listen carefully to concerns and ask questions that further our understanding. We instill trust by listening carefully and working together – and delivering on the promises we make.

To that end, our first Indigenous Reconciliation Action Plan (IRAP), and its commitments, serve as a beacon of our company-wide focus to advance reconciliation.

That said, reconciliation at Enbridge is more than what could be embodied in this plan. It requires a thoughtful approach, hard work, and respecting and acknowledging our history. Most of all it requires our full commitment to building a better future together. In my experience, this hard work is not only necessary but is always worth the effort.”

– **Al Monaco**, President and CEO

Where we are now in our journey

As a company, we strive for a future where society is united in and committed to creating an inclusive future. We have a role to play in challenging long-held beliefs about the history of Indigenous peoples and embarking on and supporting a path towards reconciliation. As we learn more, and reflect on and acknowledge our journey to date, we create a path that we can walk, together, towards reconciliation. Enbridge is responsible for forging this path – by continuing to listen to and learn about the history, culture and perspectives of Indigenous peoples and identify ways to enable, encourage and support this journey.

While we have been building relationships with Indigenous groups for many years, Enbridge made a commitment in 2017 to enhance transparency by expanding reporting on the implementation of our Indigenous Peoples Policy and the steps we are taking to integrate Indigenous rights and knowledge into our business across Turtle Island. In June 2018, we began to fulfill that commitment with the release of a discussion paper, *Indigenous Rights and Relationships in North American Energy Infrastructure*, and have since provided an annual overview of our plans, commitments and outcomes with respect to Indigenous inclusion within our 2018–2021 sustainability reports.

We most recently reported on our corporate journey towards reconciliation in February 2022 with the release of, *Continuing Our Path to Reconciliation: Indigenous Engagement and Inclusion—An Update*. Our work to date has been values-driven, focused on collaboration and has taken shape in our lifecycle approach to engagement and supply chain opportunities, and employment, education, and Indigenous cultural awareness initiatives.

> While much work has been done, there is much more to do. We have a responsibility to continue moving forward.

This, our first Indigenous Reconciliation Action Plan (IRAP), is an opportunity to continue our unwavering commitment to reconciliation. These tangible, measurable and publicly reportable commitments help to further underpin our Indigenous Lifecycle Engagement Framework by forming the next stage of our journey towards reconciliation, and support the transition towards a cleaner energy future in partnership and collaboration with Indigenous peoples.

Our commitments will require continued collaboration, patience, and a resolute commitment to advancing reconciliation. These commitments permeate across each of our four core businesses within Enbridge, transcend geographic borders and require us to focus on our role as an energy company whose projects and operations span Treaty and Tribal lands, the National Métis Homeland, unceded lands and the traditional territories of Indigenous Nations, Tribes, Governments and Groups (Indigenous groups)[2] across Turtle Island. Enbridge has consulted and engaged with more than 340 Indigenous groups in Canada and the United States.

We also acknowledge and express our gratitude to the 50 individuals from Indigenous groups across Canada and the United States who provided valued input early on in our IRAP development process, and whose insights have helped shape our commitments and the priorities for this continued journey towards reconciliation. Thank you – for your honesty, your willingness to engage, and your thoughtful contributions – all of which help direct the trajectory of this journey to reconciliation and a sustainable energy future.

Through this IRAP, and the actions we will undertake to support and advance our 22 commitments, we must create opportunities – for dialogue, for listening, for knowledge transfer, and for collaboration and partnership with Indigenous groups. Put simply, reconciliation is supported by creating connections, and furthered by building bridges that connect recognition of the past to a shared vision for the future.

IRAP vision and values

At Enbridge, our core values – Safety, Integrity, Respect and Inclusion – reflect what is truly important to us as a company. These values represent the "north star" for our organization, a constant beacon by which we make our decisions, as a company and as individual employees, every day. In 2020, we invested time and energy listening to our employees speak about their experiences, including the barriers faced by Indigenous peoples. This engagement resulted in the addition of inclusion as a core value. We are committed to upholding these values as we collectively walk a path to reconciliation.

Our name, Enbridge, has long conveyed our commitment to being a bridge and leading the way to a safer, cleaner and more sustainable energy future. We recognize we have an important role to play in building bridges toward reconciliation and in collaborating with Indigenous peoples on the energy transition as we seek to be the leading energy infrastructure company in North America.

Our vision for this IRAP is that it will:

- Guide us on our continued journey to reconciliation
- Unite and focus us in our efforts to continue to build and nurture respectful and mutually beneficial relationships with Indigenous peoples
- Enable us to collaboratively create a safer, and more accountable, respectful, sustainable and inclusive future for seven generations[3] and beyond

We believe we can achieve more together – collaboratively, respectfully, purposefully and transparently.

[3] "Seven generations" is an Indigenous sustainability principle that says that we should consider how every decision will impact and affect those seven generations into the future.

About this IRAP

This IRAP is organized into six pillars and outlines a total of 22 commitments. Full details and targets are provided in the pages that follow.

These pillars represent our priorities, a cornerstone of our commitment to reconciliation, each collaboratively developed with the input of Indigenous individuals and groups. Our pillars will endure, and while the commitments may evolve over time, we expect each pillar will remain stable and consistent. Enbridge will develop tools and mechanisms to support and execute on these commitments on our path towards reconciliation.

We will publicly report on our progress against these commitments annually, starting with an update on our progress in our 2023 Sustainability Report.

SIX PILLARS

1
People, employment and education

2
Community engagement and relationships

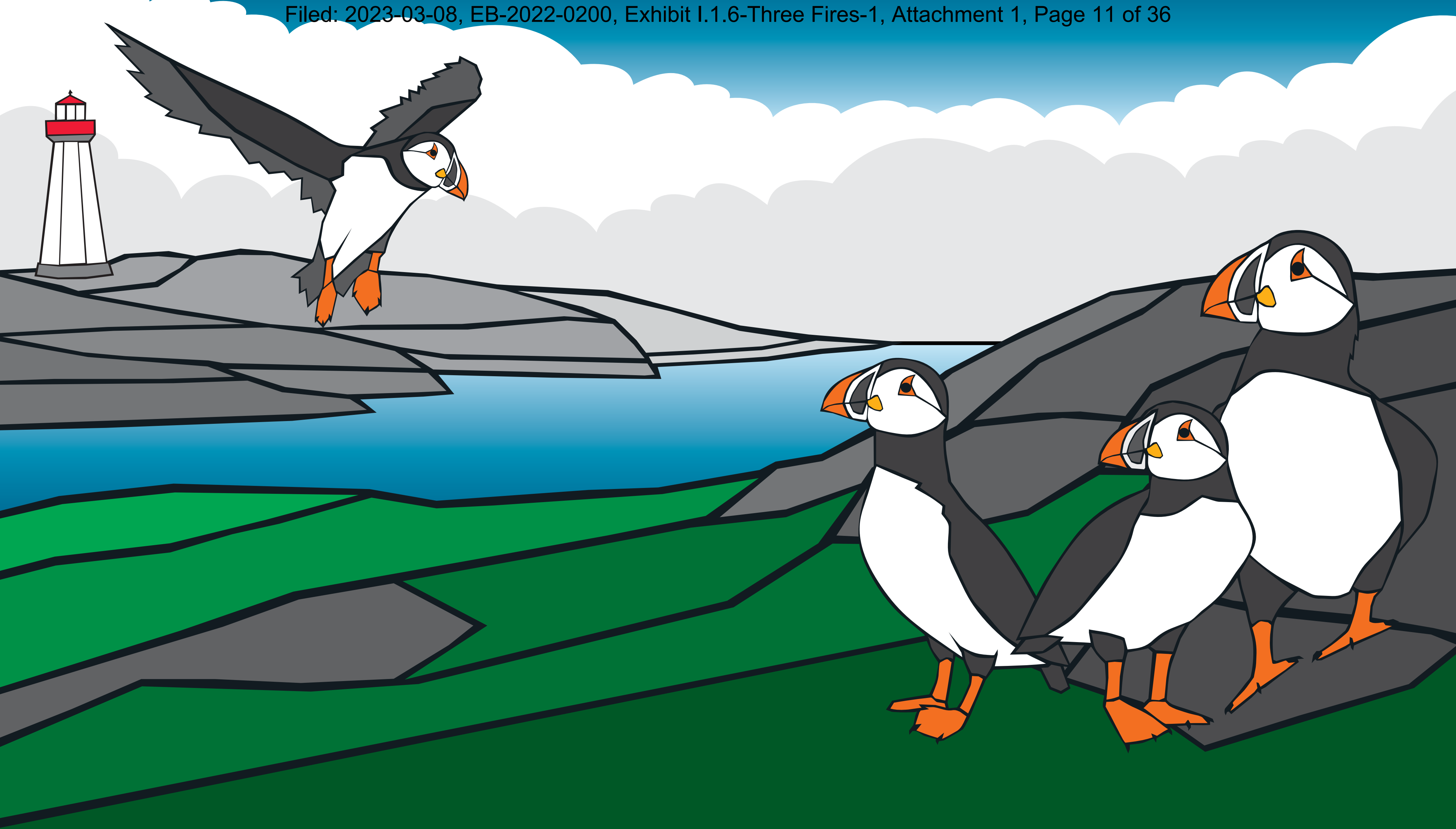
3
Economic inclusion and partnerships

4
Environmental stewardship and safety

5
Sustainability, reporting and energy transition

6
Governance and leadership

Reconciliation Action Pillars



PILLAR 1

People, employment and education

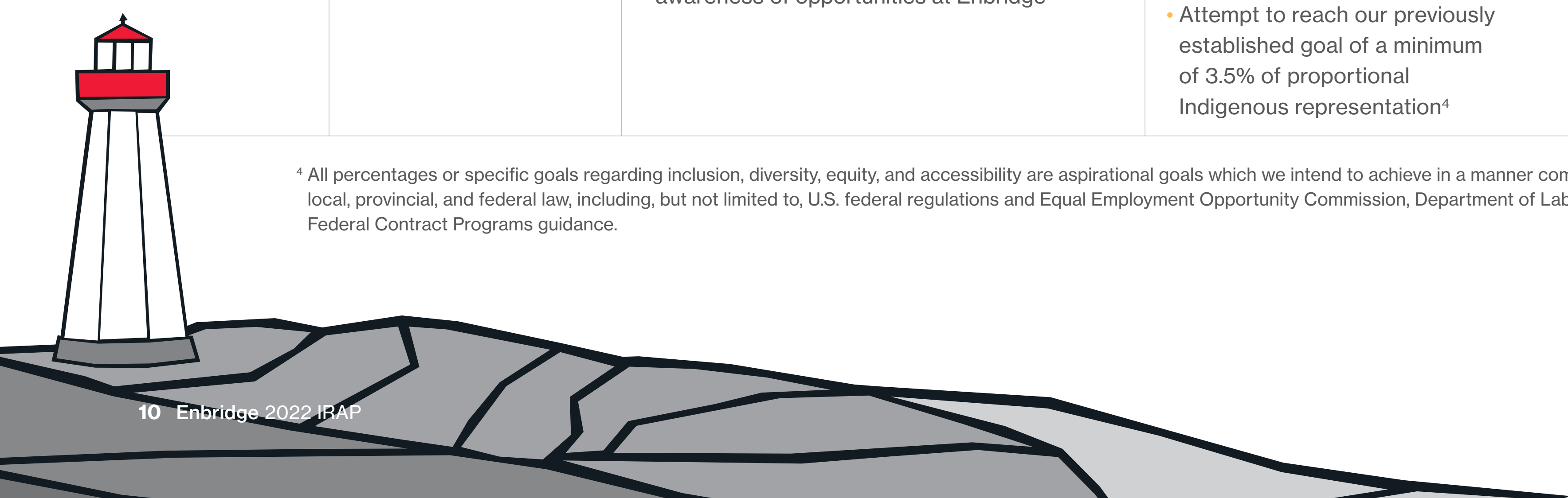
Enbridge is committed to creating and nurturing organizational structures that support opportunities to attract, retain and develop the skills of Indigenous people at all levels and in positions that make Enbridge the place to build their careers in a culturally supportive work environment.

PILLAR 1

People, employment and education

Focus	Commitment	Details	Target/Goal	Timeline
Talent attraction and recruiting	Establish flexible work placements and opportunities for Indigenous peoples that account for regional and cultural considerations across Canada and the United States	• In addition to current organizational workplace flexibility options, identify and develop opportunities for roles in other locations where there might be increased availability of Indigenous applicants • Identify and resolve employment barriers for current and future Indigenous employees • Explore updating leaves policies to reflect cultural inclusivity	• Update Indigenous engagement employment program to account for Indigenous culture, regional/remote considerations and legal considerations, as appropriate • Explore establishing a cultural leave program	2022 – Ongoing
	Continue to seek and strive to increase Indigenous representation in Enbridge's permanent workforce	• Continue to review and develop Indigenous employment data and report annually • Work with Indigenous groups and training partners to identify current opportunities and key growth areas for employment and skills development • Explore new partnerships to grow talent pool and implement Indigenous recruitment strategies with the goal of increasing awareness of opportunities at Enbridge	• Continue to report metrics and provide annual disclosure • Identify key growth areas for employment and skills development • Establish partnership with Indigenous employment agency • Attend at least eight (8) Indigenous-focused career fairs throughout Canada and the United States • Attempt to reach our previously established goal of a minimum of 3.5% of proportional Indigenous representation[4]	2025

[4] All percentages or specific goals regarding inclusion, diversity, equity, and accessibility are aspirational goals which we intend to achieve in a manner compliant with state, local, provincial, and federal law, including, but not limited to, U.S. federal regulations and Equal Employment Opportunity Commission, Department of Labor and Office of Federal Contract Programs guidance.



Focus	Commitment	Details	Target/Goal	Timeline
Talent attraction and recruiting	Continue to review internal hiring processes and develop human resource capability to ensure all perspectives are reflected through attraction/ retention lifecycle	• Review existing talent policies and procedures to identify gaps and implement changes to ensure cultural perspectives and priorities are reflected throughout process(es) • Continue to conduct regular training with Talent Acquisition team on ways to conduct culturally sensitive interviews (e.g., understanding Indigenous cultural differences, uncovering hiring biases, interviewee evaluation criteria) • Where allowed by law, formalize Indigenous attraction/retention programming for diversity, cultural, regional and remote considerations	• Review and, where appropriate, update internal hiring processes • Conduct ongoing and regular training with Talent Acquisition team related to hiring practices • Explore development of policies/ procedures to support Indigenous attraction/retention programs	2022 – Ongoing
Talent experience and development	Increase representation of Indigenous employees within Enbridge's Leadership Development Program to support the retention and advancement of Indigenous employees	• Continue to support Indigenous employees through consultation, mentorship, onboarding, coaching and connection • Develop and diversify pools of candidates for apprenticeship and internship programs • Continue to identify and develop succession plans free from unconscious bias across the company	• Explore expansion of programs and opportunities for the growth of Indigenous employees/employee base	2023 – Ongoing

* Please note that bargaining unit employees are subject to the terms and conditions of their collective bargaining agreement.

PILLAR 1

People, employment and education

Focus	Commitment	Details	Target/Goal	Timeline
Cultural support programs	Continue to develop and maintain cultural support programs to make Enbridge an attractive and welcoming employer for all people, including Indigenous peoples	• Continue to include and develop Indigenous Employee Resource Groups across the company • Expand programs related to Sharing Circles and Indigenous employee support across the company • Continue to create culturally inclusive and safe spaces across the company that are supportive and celebrate Indigenous arts and culture. • Develop a regional-based implementation model inclusive of diverse perspectives across the company • Establish an Elder connections program to give employees direct access to Indigenous Elders for advice and cultural support	• Continue to implement and expand cultural support programs • Integrate Indigenous arts and culture in Enbridge offices and facilities across Turtle Island	2023 – Ongoing
Learning and awareness	Ensure 100% of Enbridge's employees complete Indigenous awareness training	• Ensure opportunities exist for employees to develop a deeper understanding of the history, rights, culture and knowledge of Indigenous peoples by completing online or in-person cultural awareness training • Explore tailored training for groups across Enbridge, as needed • Track and monitor completion statistics of required Indigenous Awareness Training	• 100% employee participation in cultural awareness training • Ensure every new Enbridge employee receives cultural awareness training as a requirement	2022

PILLAR 1

Spotlight: Gas Distribution and Storage Mentorship Program

As an example of forging new pathways and living our values — the Gas Distribution and Storage (GDS) Mentorship Program aims at reducing barriers and increasing opportunities for Indigenous recruitment and employment.

> Wendy Landry (left) and previous mentorship participant, now full-time Enbridge employee, Lauryn Graham (right) pose next to the Enbridge sign in Eastern Region.

Enbridge's Gas Distribution and Storage (GDS) Northern Mentorship Program, now in its 4th year, was founded when our Northern Region team in GDS recognized their approach to recruit local Indigenous talent for various positions over several years was largely unsuccessful. "We have a duty to reflect the communities we serve, yet we struggled to attract local Indigenous talent after years of effort and commitment," said Luke Skaarup, former Director Northern Region Operations GDS and now Director Operations Services for Enbridge's Liquids Pipelines Operations. "We needed to work collaboratively both internally and externally to course correct."

The team sought approval for and actioned the re-purposing of Enbridge's co-operative and summer student roles for Indigenous mentorship and engaged with local Indigenous groups and unions to reduce the very real barriers to entry into Enbridge – and more generally, corporate Canada – by enhancing the accessibility of our job postings, inviting initial discussions and conducting interviews within communities. They provided recognition for relevant lived experience in addition to professional experience.

"The success in identifying and connecting candidates with positions came from the commitment and foresight of early champions of this program and a willingness to depart from the normalized hiring processes that create barriers to entry for some Indigenous candidates."

– **Wendy Landry,** Enbridge Senior Indigenous Initiatives and Engagement Advisor

PILLAR 1

Gas Distribution and Storage Mentorship Program continued

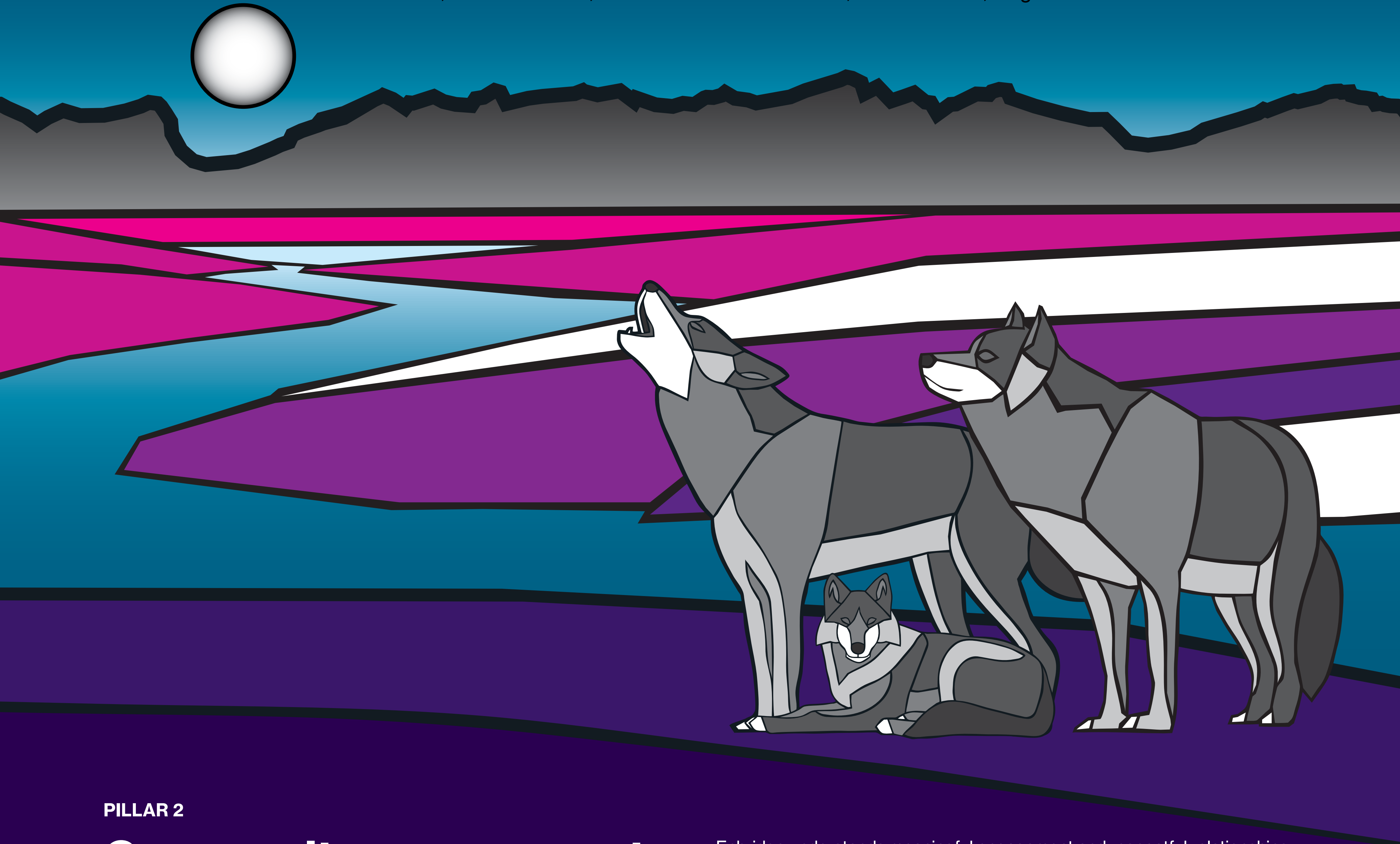
"The success in identifying and connecting candidates with positions came from the commitment and foresight of early champions of this program, and a willingness to depart from the normalized hiring processes that create barriers to entry for some Indigenous candidates," said Wendy Landry, Red Rock Indian Band member, Mayor of Shuniah and Senior Indigenous Initiatives and Engagement Advisor to Enbridge. While there is more work to do, this program has helped develop capacity by identifying where there were gaps in the recruitment and hiring process and how best to address those gaps to create pathways to employment – with Enbridge or elsewhere in the energy industry.

> The team focused internally on identifying pathways to fulltime employment, on implementing a mentorship program, and approached recruitment and hiring in a more culturally sensitive and respectful manner.

In 2021, the Northern Region team in GDS hired four mentees with an additional Indigenous employee successfully competing for a fulltime construction laborer position. We also partnered with the Métis Nation of Ontario as part of a Métis Youth Internship Program to on-board one additional hire to our construction team, and Distribution Operations initiated an Indigenous Community Outreach program as part of its diversity and inclusion strategy.

Enbridge is focused on expanding the mentorship program across GDS in Ontario in 2022, along with the implementation of an internal awareness campaign to increase understanding and support for Indigenous partnerships and collaboration.

Opportunities for dialogue and engagement with current and potential employees, including through the Indigenous Employment Resource Group and the Indigenous Sharing Circle, mean our journey of learning and adapting continues to inform the evolution of our Indigenous recruitment commitment. The entire team continues to identify mechanisms to enhance our accessibility, recruitment, retention and education practices.



PILLAR 2

Community engagement and relationships

Enbridge understands meaningful engagement and respectful relationships are foundational to advancing reconciliation. We are committed to developing strategies, mechanisms and opportunities that support and nurture dialogue and engagement between Enbridge and Indigenous groups throughout the lifecycle of our projects and operations.

PILLAR 2

Community engagement and relationships

Focus	Commitment	Details	Target/Goal	Timeline
Feedback mechanism	Develop an incremental formal mechanism for Indigenous groups to provide feedback to Enbridge	• In addition to ongoing engagement activities, and in consultation with Indigenous peoples, develop an incremental transparent feedback mechanism to facilitate input from potentially impacted Indigenous groups such as questions, concerns, and opportunities for collaborations related to Enbridge's projects and operations	• Establish and launch feedback mechanism	2023 – Ongoing
Community engagement and relationships	Provide $80 million in cumulative funding support for engagement priorities, community capacity building and fostering wellbeing over the next five years	• In addition to Enbridge's Indigenous contracting and procurement spend, these funds are intended to support community capacity and wellbeing. This may include dollars from relationship agreements, taxes paid and/or corporate/regional community investment	• $80 million in cumulative funding over five years	2022 – 2027

PILLAR 2

Spotlight: Patrick Hunter mural

How an art installation ignites and inspires conversation and connection to each other, the land and Indigenous culture and history.

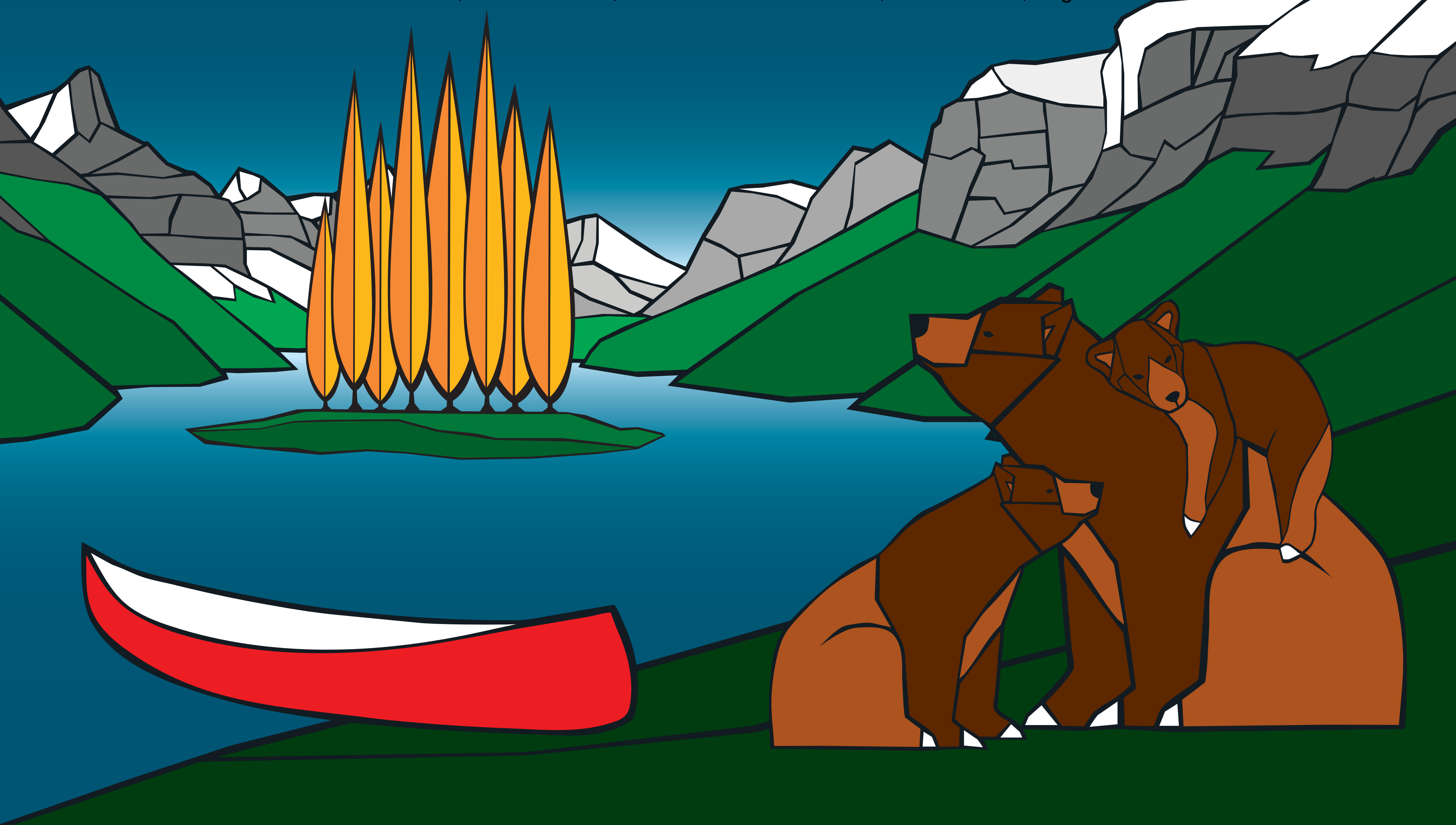
“I think it’s important for companies today to realize the land they are on was once another culture’s territory. Public acknowledgments of that fact are such a great first step towards being on the right side of history.”

– **Patrick Hunter,** Ojibway artist

Patrick Hunter is a two Spirit Ojibway artist, graphic designer and entrepreneur from Red Lake, Ontario. Patrick is one of Canada’s well-known Woodland artists, gaining inspiration from his homeland, painting what he sees through a spiritual lens, with the intent to create a broader awareness of Indigenous culture and iconography. Among his many projects are artwork he created for the Canadian Olympic Curling Team, the Chicago Blackhawks and Hockey Night in Canada.

In 2021, Enbridge commissioned Patrick to create two original pieces of art that could be digitized and used as murals in GDS facilities across Ontario. The pieces are installed in two locations: the 3rd floor of the 50 Keil Drive office in Chatham, and the 1st floor of the Victoria Park Centre in Toronto. Both pieces represent the start of a longer-term project to prominently display a collection of original Indigenous artwork.

The murals, designed specifically for Enbridge, embody Patrick’s personal reflections on and spiritual connection to the land and Indigenous territories in and around Ontario on which our GDS offices reside. They create awareness of Indigenous culture and history of the lands on which we work and live and connect us back to the natural world, something increasingly difficult to do in our urban environment. Not least, and perhaps most profoundly, they invite and ignite conversation, furthering our connections to each other and creating opportunities for dialogue, learning and reflection on our individual and collective journeys towards reconciliation.



PILLAR 3

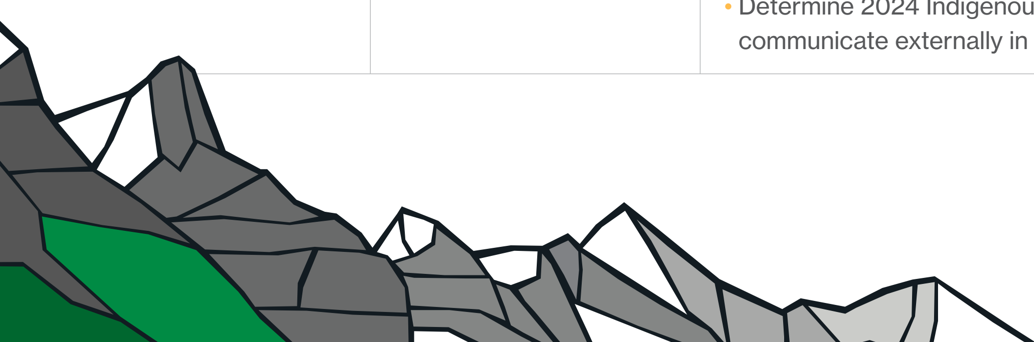
Economic inclusion and partnerships

Enbridge strives to create, engage in, and stimulate positive and mutually beneficial financial impacts, opportunities and potential partnerships with Indigenous groups and businesses.

PILLAR 3

Economic inclusion and partnerships

Focus	Commitment	Details	Target/Goal	Timeline
Indigenous financial partnerships	Revise and formalize Indigenous financial partnership processes that encourage strategies to provide opportunities for Indigenous economic participation	Establish a formal Indigenous Economic Development Taskforce to formalize processes that will: • Leverage business units' and project teams' insights to establish standards and criteria for financial partnerships within the company's investment review processes • Identify and review previous successes to develop financial opportunities that account for various regulatory, legal and socio-economic considerations • Undertake a review of the Indigenous financial capacity landscape and access to capital to ensure Enbridge facilitates opportunities that can be implemented • Engage with Indigenous groups to seek feedback and assess alignment between Enbridge's processes, market opportunities and new opportunities for Indigenous economic participation	• Develop Indigenous Economic Development Taskforce • Formalize processes and strategies for Indigenous economic participation • Implement new partnership processes and strategies that foster early engagement with Indigenous groups • Ensure Indigenous perspectives are included within review and development process(es)	2022 – Ongoing
Supplier capacity development	Advance opportunities for Indigenous businesses to participate in Enbridge's supply chain	• Develop and conduct information sessions over two years to provide guidance and education to Indigenous businesses seeking participation in Enbridge's supply chain • Continue to provide support for Indigenous businesses navigating Enbridge's procurement system	• Develop and conduct at least eight information sessions over two years	Ongoing
Indigenous procurement	Establish Indigenous spend targets	• Continue to establish benchmarks for Indigenous spend targets • Determine 2024 Indigenous spend targets and communicate externally in 2023	• Determine and disclose Indigenous spend targets	2023



PILLAR 3

Spotlight: Indigenous economic inclusion in gas transmission expansion projects in British Columbia

An expansion of B.C.'s gas transmission system created mutual opportunities and benefits for Indigenous businesses and Enbridge and shone a spotlight on the far-reaching impact and importance of Indigenous economic inclusion.

Enbridge is the owner and operator of British Columbia's (B.C.) major gas transmission system, connecting the province's natural gas exploration and production industry with millions of consumers and heating homes, businesses, hospitals and schools in B.C., Alberta, and the U.S. Pacific Northwest. Gas also fuels electric power generation and is a staple in many industrial and manufacturing processes.

In the fourth quarter of 2021, we completed two capital expansion projects – the T-South Reliability Expansion Project (TSRE) and the Spruce Ridge Expansion Program (Spruce Ridge). Enbridge conducted upgrades and reliability enhancements and expanded the capacity of the gas transmission system in B.C.

TSRE work included the installation of five new compressor units and associated equipment at five existing compressor stations, two

> These projects were completed with significant Indigenous engagement, participation and collaboration. In fact, the spend with Indigenous contractors in B.C. nearly doubled between 2018 and 2021.

compressor station cooler additions and three pipeline crossover projects. Twenty-four Indigenous groups participated and benefited economically, with Indigenous businesses securing and executing an aggregate of $54.7 million in contracts and subcontracts.

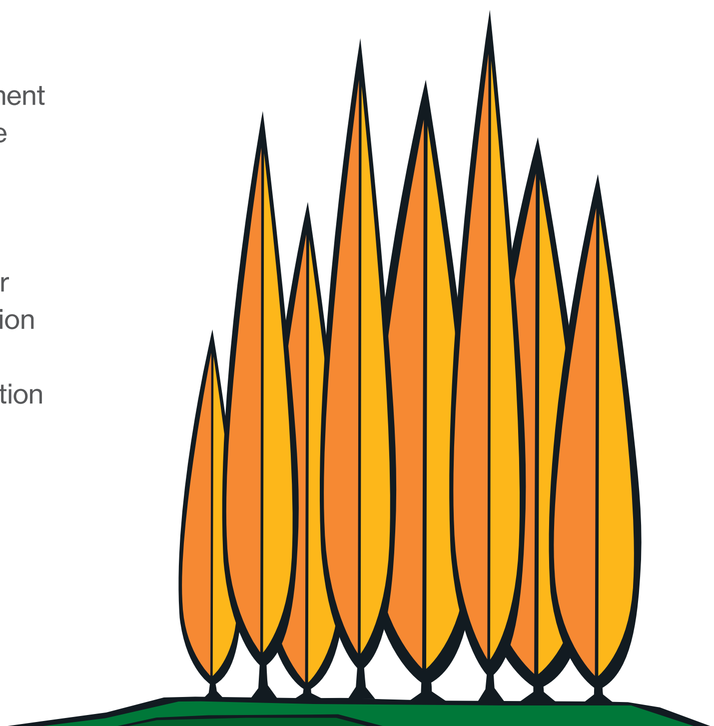
Spruce Ridge work involved the building of two new natural gas pipeline loops (the 13-km Aitken Creek Loop and the 25-km Chetwynd Loop), the addition of a new compressor unit at two compressor stations and some additional minor modifications at above-ground facilities. Nine Indigenous groups benefitted economically through subcontracting opportunities for an aggregate $66.6 million worth of contracts and subcontracts, including the award for construction of the Aitken Creek Loop to an Indigenous partner business.

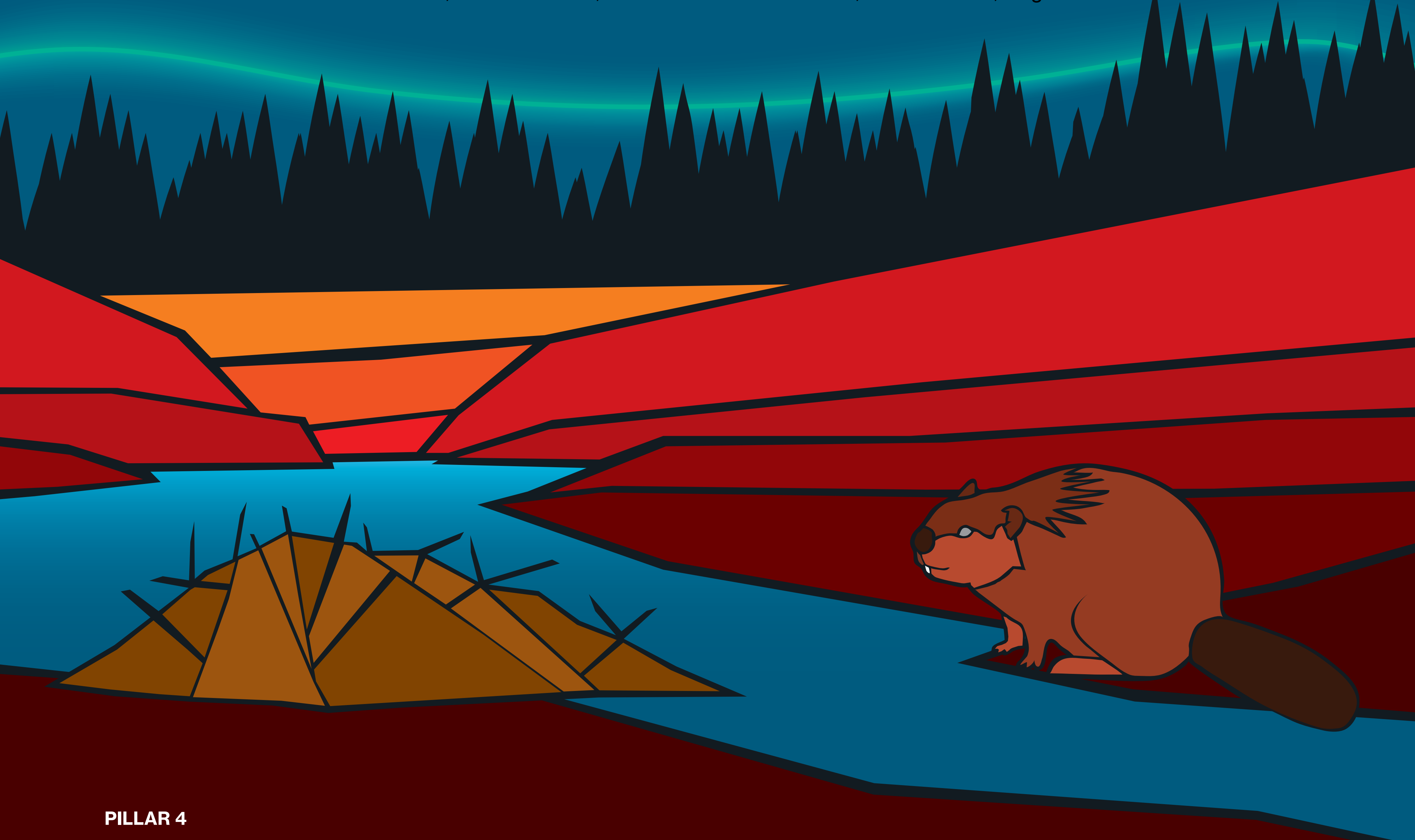
As we have walked this path towards reconciliation through the years, there have been pivotal moments along the way that have increased the momentum of our journey and created fundamental shifts in the way we do business. The focus on and implementation of measures to increase Indigenous economic inclusion and engagement is one such example of Enbridge's commitment on this journey.

The roll-out of Enbridge's Socio-Economic Requirements of Contractors (SERC) process in 2017 coincided with early engagement activities with Indigenous groups on TSRE and Spruce Ridge. The SERC guides our contractors on how we expect them to include Indigenous businesses in the execution of their work, as well as efforts to increase the use of Indigenous businesses as general contractors working directly for Enbridge. Each component of our focus on increased Indigenous economic engagement and inclusion was complemented by other mechanisms driving an increase in Indigenous economic inclusion and included targeted pre-qualification of Indigenous businesses; strategic direct award opportunities for Indigenous businesses to increase capacity and experience; and a focus on increasing capacity with Indigenous archaeology companies.

"Embracing relationships with Indigenous groups – giving them the opportunity to have a seat at the table, provide input on projects and to capitalize on opportunities is a big part of what reconciliation is [and to a further extent the implementation of UNDRIP in our daily lives]," said Chief Willie Sellars of Williams Lake First Nation.

"In addition, it's important to keep in mind the cultural, ceremonial, and traditional components of our way of life and incorporating that understanding and respect into projects. The TSRE ground-breaking at Compressor Station 6A 150 Mile House included a ground blessing, prayers and songs and provided an opportunity to introduce those present to our way of life and our traditions. This is so important as reconciliation requires education for people to be able to understand, to heal and to move forward. We are pleased to be able to work with Enbridge on this important journey towards reconciliation."





PILLAR 4

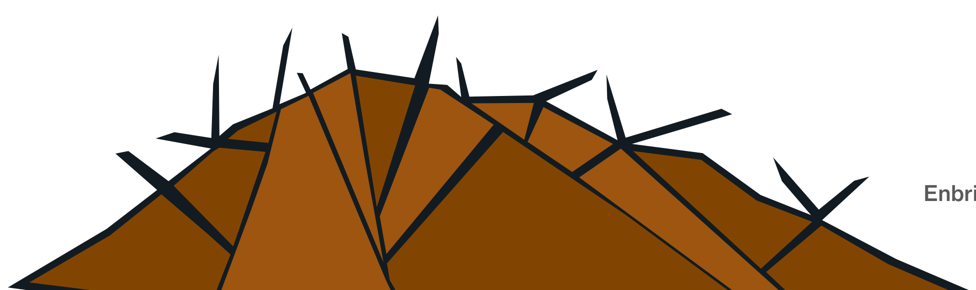
Environmental stewardship and safety

Enbridge recognizes the strong Indigenous connection to culture and the traditional importance of the land, air, animals and water. We are committed to environmental protection, collaborative stewardship, and continued improvement of engagement on, and inclusion of traditional and cultural knowledge in our plans, projects and operations.

PILLAR 4

Environmental stewardship and safety

Focus	Commitment	Details	Target/Goal	Timeline
Indigenous inclusion and traditional knowledge	Review and revise Enbridge's approach to Indigenous inclusion in the environmental review processes	• Assess current approach and identify opportunities for increased Indigenous inclusion and strengthening Enbridge's current mitigation strategies	• Confirm and utilize a phased approach to revise Enbridge's environmental review processes, as needed	2022 – Ongoing
	Regionally advance opportunities for Indigenous inclusion in environmental field work	• Regionally identify and advance opportunities for Indigenous participation in environmental field work	• Increase Indigenous involvement in fieldwork	2022 – Ongoing
Emergency preparedness and pipeline safety	Continue to share emergency management materials and encourage increased Indigenous awareness in emergency response	• Continue to share emergency management materials with Indigenous groups • Continue to generate awareness and provide opportunities for participation in emergency response exercises	• Continue to share relevant emergency management materials to generate awareness	2022 – Ongoing
	Continue to communicate with Indigenous groups regarding emergency and safety mechanisms and approaches	• Continue to provide notifications to Indigenous groups to ensure they are aware and engaged in the event of releases from pipeline systems • Develop a consistent process or protocol to share environmental and safety notices to Indigenous groups	• Proactively communicate with Indigenous groups through release notifications	2022 – Ongoing



PILLAR 4

Spotlight: Pontiac Township High School pollinator plot and Kickapoo Nation

An opportunity to advance sustainability commitments and facilitate connections that may endure for seven generations and beyond.

The Operation Endangered Species (OES) program was started in 2011 near Pontiac, Illinois, a brainchild of a group of Pontiac Township High School (PTHS) students with a biodiversity conservation initiative idea. The students approached their high school environmental science teacher with an idea to reintroduce endangered species on community pollination plots that would benefit surrounding agricultural land. The OES program at PTHS has raised US$150,000 over nine years to support the reintroduction of a species of reptile back to its native historic home range in Illinois.

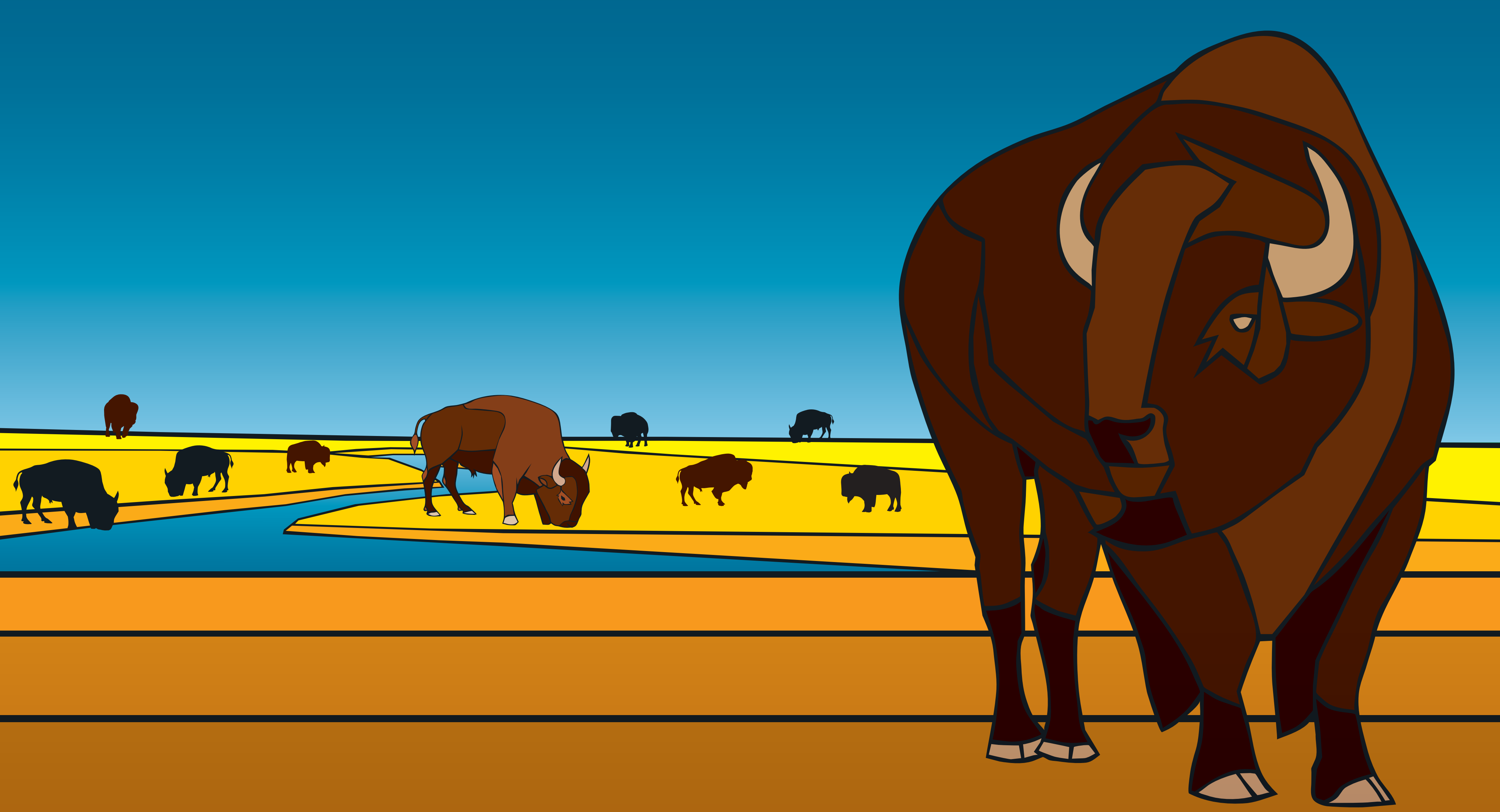
Following a US$10,000 grant from Enbridge to establish a pavilion on a nearby company-owned 20-acre pollinator plot, students from the PTHS Environmental Earth class set out to develop the land into a pollinator plot, planting native prairie grasses and other vegetation to encourage development of the natural ecosystem. In 2021, Enbridge donated the pollinator plot to PTHS and the OES program to facilitate the continuation of this meaningful and impactful conservation and community work and as part of our commitment to sustainability.

Upon completion of the land transfer, the U.S. History students of Pontiac began researching the origins of the land. They wanted to integrate respect for Indigenous groups into their ultimate use of the plot. Through this research, the students learned the land being developed as a pollinator plot in Illinois is within the ancestral lands of the Kickapoo tribe, which was one of 25 tribes forcibly relocated to Kansas between 1825 and 1850.

Through Enbridge's relationships with all parties, we were able to facilitate an introduction between PTHS, the Kickapoo tribe and the Odawa tribe, which has blossomed into a mutually respectful and engaged relationship where teachings about care and respect for the earth and ecology now occur on a weekly basis. Furthermore, Kickapoo spiritual leaders and PTHS students continue to find ways to weave cultural teachings and education opportunities together and a deep and mutual respect has been formed.

In upholding our vision for our IRAP and our role in reconciliation, we are proud to be able to facilitate connections that promote and support further learning and pathways to reconciliation that may have positive and permeating impacts for generations to come.

> “I've always believed that giving students opportunities and enabling them is the most impactful way to support them on their learning journey. The cultural learning and growth that occurred here was driven by the students, but Enbridge was a major part in helping facilitate that for them.”
>
> – **Paul,** teacher at Pontiac Township High School



PILLAR 5

Sustainability, reporting and energy transition

Enbridge is committed to forming strategies and collaborative partnerships with Indigenous groups focused on advancing the energy transition to a low-carbon economy and transparently reporting on our progress against our commitments.

PILLAR 5

Sustainability, reporting and energy transition

Focus	Commitment	Details	Target/Goal	Timeline
Reporting	Report and disclose progress on IRAP commitments in ESG and Sustainability Report	• Increase transparency by addressing progress of IRAP commitments in annual Sustainability Report	• Disclose progress via annual Sustainability Report	2023 – Ongoing
	Refresh IRAP commitments and goals every two years	• Refresh IRAP commitments and goals every two years in conjunction with input from Indigenous groups, IRAP working group, employees and Executive Leadership Team	• Publish updated IRAP commitments/ goals every two years	2024 – Ongoing
Sustainability	Facilitate a thought leader roundtable related to Indigenous inclusion and perspectives in sustainability strategy and policies	• Identify key organizations/industry partners for inclusion in thought leader roundtable discussion • Work with roundtable participants to identify relevant topics related to sustainability, climate change, Indigenous perspectives and reconciliation that further support action, identify pathways towards implementation and build capacity within Indigenous groups to support implementation • Conduct roundtable(s) with participation from Indigenous groups and industry peers	• Establish partnership(s) with Indigenous-led organizations and relevant industry peers • Convene at least one thought leader roundtable • Consider the findings and Indigenous perspectives shared at the round table(s) when Enbridge sustainability strategies and policies are updated	2023

PILLAR 5

Spotlight: The Wabamun Carbon Hub—advancing carbon capture and storage and Indigenous partnership

A "Hub" of innovation and collaboration—the Open Access Wabamun Carbon Hub creates opportunities to advance partnerships and ownership in new energy projects with Indigenous groups.

> From left to right, Chief George Arcand Jr. (Alexander First Nation), Chief Arthur Rain (Paul First Nation), Chief Tony Alexis (Alexis Nakoda Sioux Nation), and former Chief Billy Morin (Enoch Cree Nation) of the First Nations Capital Investment Partnership, partners with Enbridge to pursue ownership in future carbon transportation and storage projects.

In the fight against climate change, the International Energy Agency calls Carbon Capture and Storage (CCS) one of the world's most critical carbon reduction technologies.

As countries like Canada aim to achieve net-zero emissions by 2050, the capture and permanent deep underground storage of carbon dioxide (CO2) is being touted as a vital component of global efforts to contain those emissions from heavy industrial processes, including power generation, cement production and conventional energy production and refining.

One CCS project under development is our Open Access Wabamun Carbon Hub (the Hub) to be located west of Edmonton, Alberta, Canada.

The Hub would support recently announced carbon capture projects by Capital Power Corporation and Lehigh Cement, which represents an opportunity to avoid nearly four million tonnes of atmospheric CO2 emissions – the equivalent of taking more than 1.2 million cars off the road annually.

The Hub will remain open access for other nearby capture projects and once built, will be one of the world's largest integrated carbon transportation and storage projects, effectively doubling the amount of CO2 captured and stored today in Canada.

Engagement and dialogue about the Hub started early with Indigenous groups – even before the project was a project. The initial conversations took a "blank sheet of paper" approach and focused on

PILLAR 5

The Wabamun Carbon Hub—advancing carbon capture and storage and Indigenous partnership continued

opportunity and what could be. Through listening, learning, and acting in parallel, a partnership on the journey along this energy transition and in advancing carbon reduction, was formed.

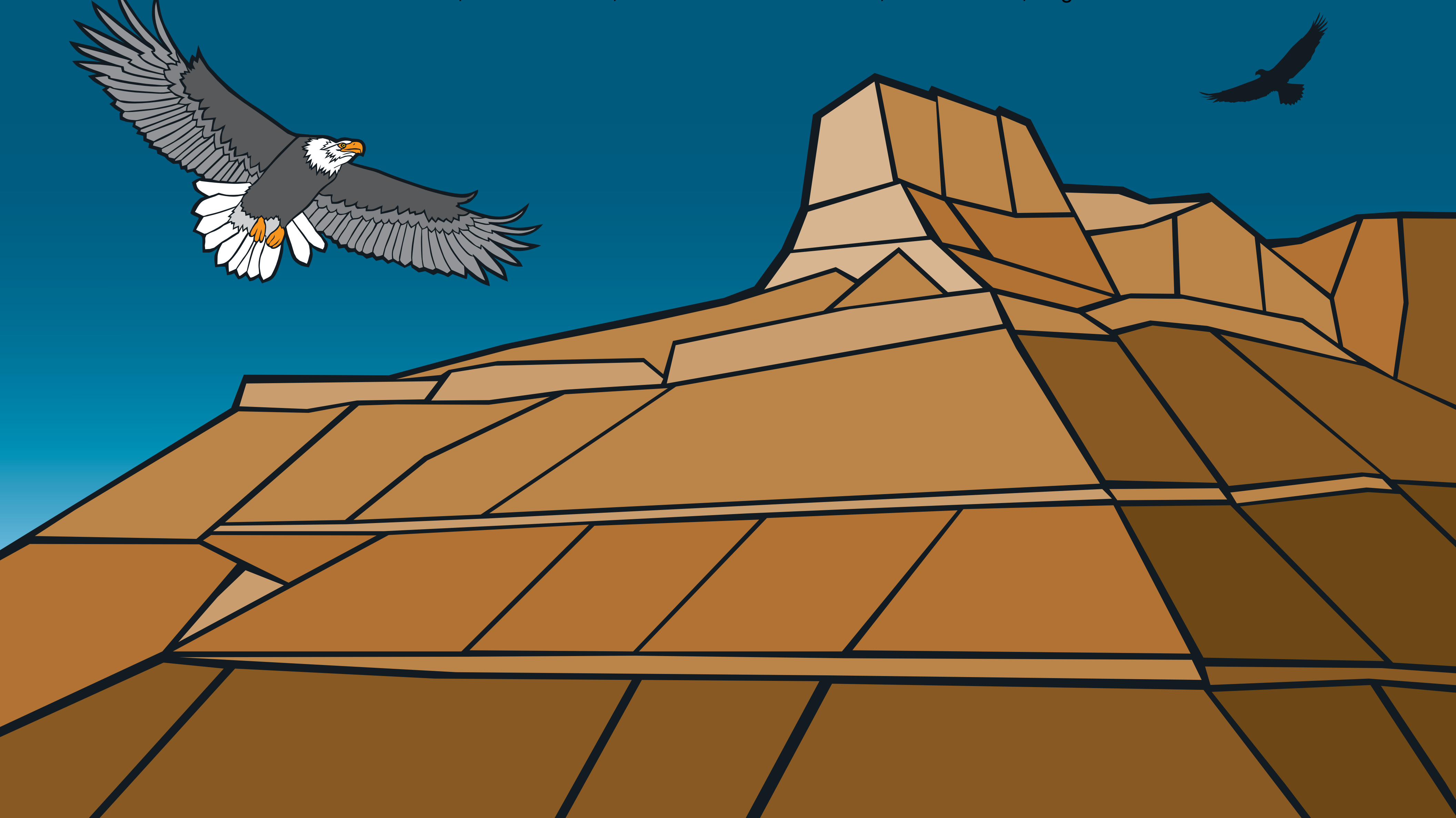
In February 2022, Enbridge and the First Nation Capital Investment Partnership (FNCIP) announced a partnership agreement to advance the Hub. The FNCIP was formed by four Treaty 6 Nations – Alexander First Nation, Alexis Nakota Sioux Nation, Enoch Cree Nation, and Paul First Nation – to pursue ownership in major infrastructure projects with commercial partners who share Indigenous values. The Hub is the FNCIP's first partnership. The Lac Ste. Anne Métis community will also have an opportunity to pursue ownership in future carbon transportation and storage projects with the Hub.

> Critically, the Hub's Indigenous partners will have an opportunity to own up to 50% of the carbon transportation and storage projects developed in connection with the Hub. This openness to co-own and co-develop the assets is ground-breaking. These projects will create long-term, stable revenues for local Indigenous groups.

“This path creates an opportunity to generate wealth, but more importantly it allows sustainable economic sovereignty for our communities. We are creating a healthy future for the next seven generations to thrive.

We're looking forward to working with industry leaders who share our values of environmental stewardship and to collaborate with Enbridge on world-scale carbon transportation and storage infrastructure investments.”

– **Chief George Arcand Jr.,** Alexander First Nation



PILLAR 6

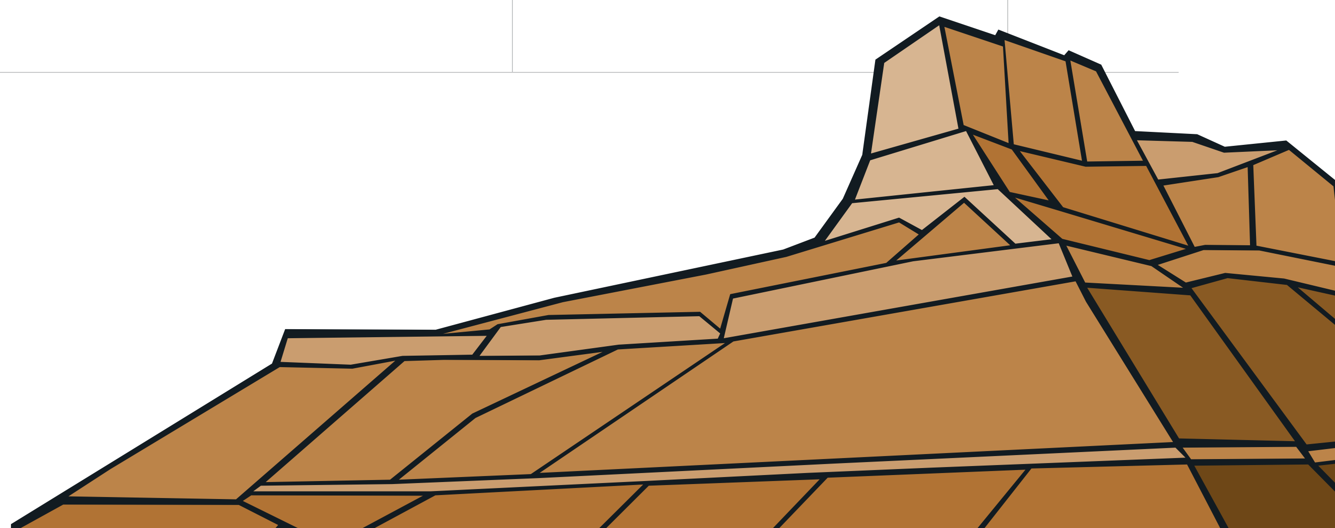
Governance and leadership

Enbridge is committed to the creation and support of governance and leadership structures that focus on embedding and promoting accountability for Indigenous engagement and inclusion across the organization. We will lead by example and hold each other accountable for the commitments we make on our reconciliation pathway forward.

PILLAR 6

Governance and leadership

Focus	Commitment	Details	Target/Goal	Timeline
Governance	Establish an Indigenous Advisory Group (IAG)	• Establish an IAG to provide advice and Indigenous and/or Tribal insight to executive management at Enbridge • Recruitment of IAG will include broad geographic representation and recruitment from diverse Indigenous groups	• Establish IAG and Terms of Reference	2023
Leadership and oversight	Ensure executive sponsorship and commitment to achieving IRAP goals	• Review executive support, sponsorship and accountability for IRAP specific commitments • Additional IRAP commitments to be linked to executive sponsorship	• Ensure IRAP performance is included in executive objectives	2023
	Ensure IRAP implementation and support mechanisms are established and aligned across the company	• Establish and maintain governance oversight for IRAP implementation and accountability	• Establish mechanisms for implementation and accountability of the IRAP	2023
Cultural awareness	Continue to conduct Indigenous Sharing Circles with participation from Executive Leadership Team	• Maintain and expand participation in Sharing Circles	• Conduct quarterly Indigenous Sharing Circles	2023 – Ongoing



PILLAR 6

Spotlight: Calgary smudge

A first-of-its-kind gathering within Enbridge provided an opportunity for personal reflection and Indigenous cultural awareness.

> A member of the Tsuu T'ina Nation west of Calgary conducts a smudge ceremony with members of our Calgary Indigenous Employee Resource Group.

In March 2022, employees were invited to gather with their colleagues, local Indigenous Elders and invited guests at our Calgary office in to participate in the first-ever indoor smudge held within our Enbridge infrastructure. The smudge experience, despite the large team gathered and being a first for most attendees, was deeply personal, reflective and spiritual.

The session was opened with a blessing and teachings by a local community Elder and led by Enbridge's Calgary chair of the Indigenous Employee Resource Group (IERG), an 18-year veteran of Enbridge and a Saulteaux member of the Cote First Nation. The smudge and teachings were a powerfully moving experience. "This event embodied the true spirit of reconciliation," said Edie Severight. "Providing an opportunity for respectful education, and exposure to important Indigenous cultural traditions in a safe and inclusive way creates crucial space for learning and connection."

This event was supported by the senior executive team and attended by management, there were extensive approvals required to facilitate permits and manage the logistics of the smudge. The ceremony created an opportunity for awareness, learning and dialogue around the rich cultural practices of Indigenous peoples.

“Smudging is an opportunity to reflect, cleanse the air and connect to the Creator. I look forward to sharing this ritual with my colleagues through many season changes to come.”

– **Edie Severight,** Law Analyst and Chair of Indigenous Employee Resource Group (IERG), Calgary chapter

The journey ahead

Our commitment to this journey is steadfast. Our goal is to create and nurture sustainable, respectful and mutually beneficial relationships with Indigenous groups in the areas in which we operate.

Our approach to Indigenous engagement and inclusion is continuously evolving. Our journey of reconciliation is a journey of continual listening, learning, reflection and action.

This IRAP is an evolutionary milestone – we are committed to this work, to continue to challenge ourselves, our leaders, and our suppliers to walk a shared path to reconciliation and to taking an innovative and progressive approach to collaboration and inclusion.

2022 Indigenous Reconciliation Action Plan

About the animals

Puffin: is an incredible social creature that is often used as a symbol of transformation (due to their ability to be a sea bird and a land-based bird). Not only celebrated for their plucky and joyful disposition, they are often thought to carry much wisdom and can offer much guidance.

Wolf: represents loyalty, strong family ties, good communication, understanding, education and seeker of higher intelligence. Of all land animals, the wolf is found all around the world and is considered to be a connector of all.

Bear: represents authority, good medicine, courage and strength. The bear is believed to be a healer and protector (like a mother bear protects her young). This animal is a symbol for standing up for what is right and fighting for what is good and true.

Beaver: is a symbol of stewardship and safety because he uses his natural gifts wisely for his survival. The beaver is also celebrated as an animal that alters their environment in an environmentally-friendly and sustainable way for the benefit of all their family.

Bison: sustained a way of life for Indigenous peoples for centuries. The bison was used as a food source throughout the years, its hides used in teepees and clothing, and its bones fashioned into tools. This animal symbolizes protection, prosperity, courage, strength, abundance, gratitude and most importantly, stability.

Eagle: is a symbol of strength, authority and power. It rules the skies with grace and great intellect. As a source of inspiration and sometimes used as a guiding force, the eagle teaches individuals about the value of the high road and the unparalleled joys of true freedom.

ENBRIDGE®
Life Takes Energy®

2022 Indigenous
Reconciliation Action Plan

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Enbridge Inc. Indigenous Peoples Policy

ENBRIDGE
Life Takes Energy

August 2022

Enbridge Indigenous Peoples Policy

Purpose: Enbridge recognizes the diversity of Indigenous peoples[1] who live where we work and operate. We understand that certain laws and policies – in both Canada and the United States – have had destructive impacts on Indigenous cultures, languages, and the social and economic well-being of Indigenous peoples. Enbridge recognizes the importance of reconciliation between Indigenous peoples and broader society. We are committed to building positive and sustainable relationships with Indigenous peoples, based on trust and respect, and focused on finding common goals through open dialogue.

Enbridge believes: Companies can play a role in advancing reconciliation through meaningful engagement with and inclusion of Indigenous peoples and perspectives in their business activities.

Policy: As an energy infrastructure company whose operations span Treaty and Tribal lands, the National Métis Homeland, unceded lands and the traditional territories of Indigenous groups[2] across North America, Enbridge is deeply committed to advancing reconciliation with Indigenous peoples. Our mutual success depends on the ability to build long-term, respectful and constructive relationships with Indigenous groups near Enbridge's projects and operations throughout the lifecycle of our activities. To achieve this, Enbridge will govern itself by the following principles:

Respect for Indigenous rights and knowledge

- We recognize the importance of the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) in the context of existing Canadian law, and the legal and constitutional obligations that governments in both Canada and the United States have to protect those rights.
- We recognize the legal and constitutional rights possessed by Indigenous peoples in Canada and in the Unites States, and the importance of the relationship between Indigenous peoples and their traditional lands and resources. We commit to working with Indigenous communities in a manner that recognizes and respects those legal and constitutional rights and the traditional lands and resources to which they apply, and we commit to ensuring that our projects and operations are carried out in an environmentally responsible manner.
- Consistent with Enbridge's respect for the rights of Indigenous peoples, we engage early and sincerely through processes that aim to achieve the support and agreement of Indigenous nations and governments for our projects and operations that may occur on their traditional lands.
- We seek the input and knowledge of Indigenous groups to identify and develop appropriate measures to avoid and/or mitigate the impacts of our projects and operations that may occur on their traditional lands.

[1] In Canada, Indigenous peoples has the meaning assigned by the definition *aboriginal peoples of Canada* in subsection 35(2) of the *Constitution Act*, 1982, which includes First Nations, Métis and Inuit Peoples. In the United States, Enbridge refers to Indigenous peoples as all descendants of people inhabiting land within the current exterior boundaries of the United States prior to the continent being inhabited by European settlers, including all U.S. federally recognized tribes.

[2] The collective term "Indigenous groups" is used in this Policy when referring to Enbridge's engagement with Indigenous nations, governments or groups in Canada, and/or Native American Tribes and Tribal associations in the United States about Enbridge's projects and operations. Enbridge has the utmost respect for the unique rights and individual names of Indigenous groups across North America. This collective term is used solely for the purpose of readability of the policy.

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Promoting equity and inclusion

- Recognizing the need to eliminate the significant socioeconomic barriers that continue to prevent Indigenous peoples from fully participating in the North American economy, Enbridge works with Indigenous peoples to ensure they have opportunities to be included in socioeconomic benefits resulting from our projects and operations. These may include partnerships and opportunities in training and education, employment, procurement, equity participation, business development and community development.
- We are committed to increasing Indigenous representation in Enbridge's workforce and supplier community.

Fostering awareness through education

- We are building – and will continue to ensure – a foundational understanding of the rights, history and cultures of Indigenous peoples through Indigenous awareness training for all Enbridge employees, with the aim of advancing reconciliation with Indigenous peoples

Enbridge will provide ongoing leadership and resources to ensure the effective implementation of the above principles, including the development of implementation strategies and specific action plans, and report its Indigenous reconciliation efforts – including engagement and inclusion outcomes – through its annual Sustainability Report.

This Policy is a shared responsibility involving Enbridge and its affiliates, employees and contractors, and we will conduct business in a manner that reflects the above principles. We will work with our contractors, joint venture partners and others to support consistency with this policy. Enbridge commits to periodically reviewing this policy to ensure it remains relevant and meets changing expectations.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Three Fires Group Inc. (Three Fires)

Interrogatory

Reference:

Exhibit 1, Tab 6, Schedule 1
Exhibit 1, Table 6, Schedule 1, Attachment 1
Exhibit 1, Tab 10, Schedule 2

Preamble:

Enbridge's customer engagement found that customers prefer some investment in renewable natural gas (**RNG**), but there is no strong consensus on the amount. Enbridge has proposed recovering the incremental costs associated with this energy through the proposed cost recovery mechanism.

Enbridge's recognizes that under the federal Clean Fuel Regulation (**CFR**) it can voluntarily participate in the CFR by generating, trading, and selling credits from covered activities, including from RNG.

Enbridge's proposed approach under its Energy Transition Plan will allow Enbridge to contract for RNG as part of regular business activities.

Question(s):

a) Please provide the exact figure quantifying Enbridge's RNG regulated and unregulated assets in Ontario, and please provide an estimate of the future growth in these assets either as a result of customer demand or government policy.

Response:

a) Enbridge Gas declines to provide specific information about the value of unregulated assets but notes that it does and will comply with the requirements of the OEB's Affiliate Relationships Code.

   - As of December 31, 2022, Enbridge Gas has gross regulated RNG assets of $5.2 million.

- Enbridge Gas estimates the CapEx growth in regulated assets over the next 5 years is approximately $95 million.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 7, Schedule 1, pp. 12 & 20

Question(s):

Enbridge Gas stated that the attrition rate for meter reading personnel in 2022 is 20% and the level of absenteeism is 17%, the highest that Enbridge Gas has experienced, which has contributed to the challenge of achieving staffing levels required to meet the MRPM.

Part of Enbridge Gas's mitigation plan to meet the MRPM includes working with meter reading vendors to hire additional readers and engaging and providing assistance to customers to submit meter reads.

a) Please expand on Enbridge Gas's plans to increase staffing levels required to meet the MRPM.

b) How does Enbridge Gas plan to accommodate the additional time and resources required to onboard new staff? Has Enbridge Gas implemented initiatives to reduce the attrition rate of meter reading personnel?

c) What is the percentage of customer meter submissions rejected by Enbridge Gas?

d) Please expand on Enbridge Gas's plans to engage and provide assistance to customers to provide their own meter reads. Does Enbridge Gas have plans to increase customer training on meter reads (through videos on its website) in order to reduce the number of rejected meter submissions?

e) Please confirm if a customer has to be on e-billing in order to submit a meter read (by phone or online).

Response:

a) Enbridge Gas is continuously working with vendors to enhance their hiring process and ensure they continue to hire additional resources. In 2022, vendors added 21 additional staff in various areas of the province to ensure consistency in meter reading. Additionally, they offered incentives to work evenings and weekends. Enbridge Gas also works with vendors to ensure they maintain competitive pay for their staff. As the employment market improves, meter reading vendors are starting to see an increase in applicants. Both attrition and absenteeism continue to be reviewed regularly and hiring is ongoing to ensure we continue to see improvements.

b) Meter Reading vendors have streamlined their hiring processes to ensure the effectiveness of new meter readers. New staff are now on-boarded and trained in approximately two weeks. The screening process has also improved so new employees better meet the requirements necessary to perform the meter reading function and reduce attrition. These processes are vital to ensure new meter readers and able to effectively complete their routes.

c) For 2022, the percentage of customer meter read submissions being rejected by Enbridge Gas is 1.96%

d) Enbridge Gas continues to send emails and letters to customers with consecutive estimates requesting their assistance by submitting a meter reading. Enbridge Gas provides multiple options for a customer to submit a meter reading, including: the Enbridge Gas website, through MyAccount, in the call centre IVR and through a live agent call. Both the website and MyAccount provide customers with a video[1] on how to submit reads. The IVR option provides step by step directions as customers navigate through the flow and agents provide instructions to customers on the call. Most customers have an understanding, which makes the number of customer meter read submissions being rejected very low.

e) Not Confirmed. Customers do not have to be on eBill to submit a meter read by phone or online.

[1] Enbridge Gas. My Gas Meter. My Account. https://myaccount.enbridgegas.com/My-Account/My-Gas-Meter .

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 7, Schedule 1, p. 14

Question(s):

Enbridge Gas is requesting partial exemption under Section 1.5.1 of the Gas Distribution Access Rule (GDAR) related to certain service quality requirements (SQR) performance measures beginning in 2024 for the rebasing period or until the OEB orders otherwise, specifically: Call Answering Service Level (CASL), Time to Reschedule a Missed Appointment (TRMA) and Meter Reading Performance Measurement (MRPM). Enbridge Gas requested the following modified measures:

- CASL – achieve 65% of calls reaching the general inquiry number answered within 30 seconds;
- TRMA – attempt to contact customers requiring a rescheduled appointment within one business day of the original appointment window 98% of the time; and
- MRPM – achieve no more than 2% of meters with consecutive estimates for four months or more.

a) Please confirm if Enbridge Gas is also requesting an exemption of these SQR performance metrics for 2022 and 2023. If so, please confirm if Enbridge Gas's requested modified performance measures for 2022 and 2023 are the same as those requested for 2024.

b) Please describe the customer impact of Enbridge Gas's proposed modifications to the CASL, TRMA and MRPM measures.

Response:

a) Regarding 2023, Enbridge Gas applied to the OEB on October 27, 2022 for a one-year exemption for 2023, for the same modified performance measures to CASL, MRPM, and TRMA as stated in the 2024 Rebasing Application (2023 Application) and the 2023 Application is provided at Attachment 1. On December 23, 2022, Enbridge Gas was notified by the OEB,[1] that the 2023 Application will not be processed at this time, as this proposal to revise Enbridge Gas's SQRs is also a matter in this 2024 Rebasing proceeding. However, Enbridge Gas notes that issue 40 on the approved issues list in this proceeding (set out below) does not currently reflect the 2023 Application and Enbridge Gas is requesting in the March 8, 2023 cover letter to these interrogatory responses that the OEB to clarify its intent in this regard.

> *40) Should the OEB grant Enbridge Gas's request for a partial exemption for 2024 from the Call Answering Service Level, Time to Reschedule a Missed Appointment and Meter Reading Performance Measurement targets set out in GDAR?*

Regarding 2022, Enbridge Gas had not intended to request an exemption from SQR performance metrics for 2022 because it was assumed that the Assurance of Voluntary Compliance (AVC) was determinative of 2022 GDAR performance metrics. However, since filing its application in this proceeding, Enbridge Gas has provided further reporting to OEB staff regarding its 2022 performance. The OEB's letter to Enbridge Gas is provided at Attachment 2 and Enbridge Gas's response is provided at Attachment 3.

Consistent with Attachment 3, Enbridge Gas maintains that it is in compliance with its commitments in the AVC and that the AVC is determinative of its 2022 performance in this regard. In the event that the OEB disagrees with this interpretation, Enbridge Gas requests that the OEB determine any outstanding matters with respect to Enbridge Gas's 2022 GDAR performance in this proceeding as part of issue 40.

b) Enbridge Gas considered customer impacts in its proposal to modify performance measurements. Enbridge Gas believes the proposal recognizes changes in customer behaviour and expectations while at the same time aligns with the performance standards for electric utilities. The proposed exemption would balance achieving the metrics, providing a positive customer experience and the cost to customers. The potential impact to customers of the modified metrics is:

- The proposed CASL metric of 65% will achieve a high-performance standard to meet customer expectations while at the same time aligning with the electric utilities to provide a consistent level of service across the utilities. An increasing trend in call complexity means that Enbridge Gas cannot answer as many calls in the 30 second CASL requirement. The revised metric would allow Enbridge Gas's

[1] EB-2022-0276, OEB Letter, December 23, 2022. OEB_Response Final EGI GDAR Exemption Request_20221223 (1).PDF

agents additional time to handle the longer, more complicated calls to provide a better customer experience.

- The proposed TRMA metric aligns with the electric utilities requiring an appointment to be rescheduled within one business day. The change in performance standard from 100% to 98% will have minimal impact on customers as Enbridge Gas consistently exceeds the Appointments Met metric, with a small percentage of four-hour window appointments requiring a reschedule. In 2021, there were 51,821 four-hour window appointments and 54 of those appointments were not rescheduled within two hours of the original appointment window.

- The proposed MRPM of 2% aligns with the changes in extreme weather events and customer behaviour observed post pandemic. Since the pandemic, access to meters has become more difficult and reading meters safely is becoming more challenging with the increase in dog ownership.

ENBRIDGE

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Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

VIA RESS

October 27, 2022

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2022-0276
Gas Distribution Access Rule - Exemption Application

Enclosed please find the application filed by Enbridge Gas with the OEB for a partial exemption from the service quality requirements set out in the subsections 7.3.1.1, 7.3.3, and 7.3.4.2 of the *Gas Distribution Access Rule*.

Please contact the undersigned if you have any questions.

Yours truly,

Lesley M Austin
Digitally signed by Lesley M Austin
Date: 2022.10.27 13:14:50 -04'00'

Lesley Austin
Advisor Regulatory Applications

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board's *Gas Distribution Access Rule*;

AND IN THE MATTER OF an application by Enbridge Gas Inc. under section 1.5.1 of the *Gas Distribution Access Rule* for a partial exemption to certain performance standards in section 7.

APPLICATION

1. Introduction

1. Enbridge Gas Inc. (Enbridge Gas or the Company), the applicant, was formed by the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Limited on January 1, 2019, pursuant to the *Ontario Business Corporations Act*, R.S.O. 1990, c. B. 16. Enbridge Gas is the largest natural gas distribution, transmission and storage company in Ontario, currently serving approximately 3.8 million gas distribution customers across Ontario.

2. Enbridge Gas hereby applies to the Ontario Energy Board (OEB) for a partial exemption from the performance measures or service quality requirements (SQRs) set out in the following subsections of the *Gas Distribution Access Rule* (GDAR): 7.3.1.1 Call Answering Service Level (CASL), 7.3.3 Meter Reading Performance Measurement (MRPM) and 7.3.4.2 Time to Reschedule a Missed Appointment (TRMA), for a one-year period, from January 1, 2023 to December 31, 2023. For ease of reference, these GDAR subsections are set out in Attachment 1 to this application (Application).

3. Enbridge Gas also recommends that the OEB's Chief Executive Officer review and amend these GDAR performance measures as soon as practicable with a view to modernizing the GDAR to achieve better alignment with customer behaviour and

expectations and similar performance measures in the OEB's *Distribution System Code* (DSC).[1]

2. Background

4. Enbridge Gas has reported annual SQR results to the OEB since these measures were added to GDAR and came into affect on January 1, 2007.[2] Additionally, following the MAAD Decision[3] in August 2018, Enbridge Gas developed its performance scorecard to include the SQRs, and the scorecard results are filed annually in the Company's Utility Earnings Sharing and Deferral and Variance Account Clearances proceedings.[4] Enbridge Gas will also provide its scorecard results with five years of history in as part of its 2024 Rebasing Application.[5]

5. As described below, Enbridge Gas was unable to meet all SQRs for 2021, and through the OEB's processes for compliance, provided an Assurance of Voluntary Compliance (AVC) in September 2022 and paid an administrative penalty of $250,000. The AVC addresses the Company's efforts to achieve the SQRs for 2022. Within the AVC, Enbridge Gas has committed to mitigation plans for 2022 that aim to meet the CASL target of answering 75% of calls within 30 seconds with a minimum of 40% monthly; the Abandon Rate (AR) of not more than 10% on a yearly basis; and a 4% MRPM (3% when accounting for meters that Enbridge Gas cannot access). Additionally, Enbridge Gas agreed to monthly reporting to OEB staff on its progress and to advise OEB staff of the occurrence and impact of any extraordinary events as soon as reasonably practicable once they are known to the Company. For clarity, Enbridge Gas interprets the AVC as addressing the Company's SQR performance for 2022 and therefore has not included an exemption request for 2022 as part of this or any other application. Enbridge Gas

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[1] https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2022-09/Distribution-System-Code-DSC-20221001.pdf
[2] EB-2005-0453, OEB Amendments to the Gas Distribution Access Rule, March 27, 2006, pp.1-2.
[3] EB-2017-0306/EB-2017-0307, OEB Decision and Order Enbridge Gas Distribution Inc. and Union Gas Limited Application for Amalgamation and Rate-Setting Mechanism, August 30, 2018, pp.52-53.
[4] Utility's Earning Sharing and Deferral and Variance Account Clearances Proceedings: 2019 – EB-2020-0134; 2020 – EB-2021-0149; and 2021 – EB-2022-0110.
[5] EB-2022-0200, EGI 2024 Rebasing Application, anticipated to be filed October 31, 2022.

requests that the OEB advise as soon as possible if this interpretation is erroneous so that Enbridge Gas may revise this application to also seek exemption relief for 2022, consistent with the AVC.[6]

6. During the Company's annual Utility Earnings Sharing and Deferral and Variance Account Clearances proceedings, the OEB found that the 2024 rebasing proceeding is "the appropriate time to review historical performance trends and consider customer implications before making any adjustments to the performance scorecard."[7] Therefore, as noted above, Enbridge Gas is addressing its SQR performance challenges for 2024 and beyond in its 2024 Rebasing Application.

2.1. 2021 SQR Results

7. Enbridge Gas was unable to meet the performance standard for four SQRs in 2021 due to factors including the COVID-19 pandemic, staffing issues, and extreme weather events. Those measures are:
   - CASL;
   - AR;
   - MRPM; and
   - TRMA

   In addition, the performance standard for MRPM was not attained in 2020 and 2019. The 100% performance standard for TRMA has historically not been met.

8. In mid-2021, the OEB initiated a review of the Company's compliance with CASL and MRPM. The compliance review was initiated as a result of an increased number of customer complaints to the OEB about Enbridge Gas meter reading, estimated bills and call centre wait times. Following the compliance review, Enbridge Gas shared its mitigation plans with the OEB, proposed SQR targets for 2022 and Enbridge Gas

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[6] EGI-Assurance-of-Voluntary-Compliance-20220912.pdf (oeb.ca), p.8.
[7] EB-2021-0149, OEB Decision and Order Enbridge Gas – 2020 DVA & Earnings Sharing Proceeding, January 27, 2022, p.12.

provided the AVC as a commitment to take all reasonable steps necessary to meet call answer performance measures[8] and to establish and meet improved meter reading performance metrics for 2022.

9. Enbridge Gas has taken all reasonable steps in striving to achieve the SQRs on a consistent basis. Factors contributing to not reaching the SQRs in recent reporting periods include the COVID-19 pandemic, staffing issues, system integration and extreme weather events. Throughout 2020 and 2021, Enbridge Gas took proactive steps to manage through changes and challenges and meet the performance standards for all SQRs. Those steps included:
    - Customer Communications – Communications were developed and delivered months prior to Customer Information System (CIS) integration, notifying customers of expected impacts including updated log in and payment information. Communications used multiple channels including email, the website and the Interactive Voice Response (IVR). Prior to the integration of the CIS system, communication plans were shared with OEB staff providing an opportunity for questions and comment on the integration taking place. To address meter reading performance, similar communication channels were used to assist customers in submitting meter reads to decrease the number of consecutive estimates used to produce customer bills.
    - Digital Channels – Enbridge Gas introduced additional online self-serve options for customers in 2019, including a “chatbot” to answer less complex questions such as account balance inquiries. Following system integration all digital channels were aligned and available to all customers.
    - Staffing – Where possible, temporary staff were hired to assist with the increase in call volumes and absenteeism. In addition, staff were redirected to focus on addressing customer concerns that were resulting in increased calls such as resolving billing issues.

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[8] Call answer performance measures in the EGI Assurance of Voluntary Compliance pertains to both CASL and AR.

- Labour Shortage – Enbridge Gas assisted key vendors in hiring staff to address the labour shortage. In addition, Enbridge Gas worked with vendors to support retention of staff.
- Training – Prior to the CIS system integration implementation call centre staff underwent extensive training on the new system and new scripts to ensure agents were able to answer questions and resolve issues effectively.
- Systems Integration – Enbridge Gas continues to integrate systems and align processes in an effort to provide an efficient and consistent customer experience. Integration of systems such as CIS and the work management systems are necessary and beneficial, however, they can require an initial change for customers, can take time to transition and can create an initial learning curve for employees. Systems integration supports consistent and aligned processes for the benefit of customers.

10. Safety continues to be the top priority and a core value of Enbridge Gas. During the COVID-19 pandemic, there were periods of time when meter readers were unable to complete routes due to public health stay at home orders. The stay-at-home orders also led to more people being at home during the day, increasing interactions between meter readers and homeowners. There was also an increase the number of dogs in backyards with more people being home. This led to increased safety concerns and dog bites. COVID-19 safety and quarantine periods were also impactful, as the well-being of staff that were ill and staff that could come in contact with ill co-workers was a concern. In addition, provincial guidelines and the requirement to adhere to quarantine/isolation periods that ranged between 5 to 14 days created resourcing challenges that impacted meter reading performance. To provide further context, approximately 4,000 meters can be read by one meter reader in a five day work week, therefore if a meter reader is unable to conduct reads for a 14 day quarantine/isolation period (10 business days) 8,000 meters could go unread.

11. Finally, extreme weather such as freezing rain, flooding and heavy snow impacted the ability to obtain meter reads as roads were too dangerous to travel on or in some cases were closed. Responding to emergencies was and continues to be a priority for Enbridge Gas, and from time-to-time field staff and dispatch staff are re-directed from customer appointments to attend emergencies impacting the ability to reschedule appointments according to the prescribed timelines.

2.2. Call Answering Service Level

12. CASL tracks the percentage of calls reaching the general inquiry number, including IVR calls that are answered within 30 seconds. The yearly performance standard for CASL is 75% with a minimum monthly standard of 40%. The 2021 annual result was 64.3%; however, Enbridge Gas did achieve the minimum monthly standard of 40% in all months. Prior to 2021, Enbridge Gas met the performance standard for CASL on a consistent basis.

13. Enbridge Gas consolidated its CIS systems in July 2021, migrating 1.6 million Union rate zone customers from the CIS in use that was approaching end of life to a single CIS on the platform in use for EGD rate zone customers. The transition of customers to the SAP CIS also introduced these customers to a new customer-facing website, online billing and IVR systems. The change resulted in a significant increase in call volumes and call complexity in 2021. The move to one CIS benefitted customers through efficiencies created by integrated and consistent processes related to call handling, billing and customer experience.

14. As part of this integration project, customers were required to update passwords and banking information and some customers experienced issues with billing data converted during system integration, all of which increased calls to the call centre. Anticipating an increase in call volumes, additional temporary employees were hired to support the transition. Also, prior to the integration, each call centre employee underwent extensive training on the SAP CIS. All the training was virtual due to the pandemic restrictions for

in class training, resulting in reduced "hands-on" training and experience. Over the same period Enbridge Gas experienced a shortage of resources in the call centre due to increased illness and absences related to the COVID-19 pandemic. While Enbridge Gas added temporary staffing, adding enough temporary staff to cover all absences due to COVID-19 outbreaks was not practical. It takes up to four weeks for call centre staff to be initially trained to answer calls related to customer moves and an additional two weeks of training to answer more complex calls such as billing calls or questions on changes to rates.

15. The annual call volumes prior to the pandemic in 2019 were 3,588,323 and the average call handling time was 7 minutes and 7 seconds. In 2021 the annual call volumes were 3,609,331 and the average call handling time was 8 minutes and 14 seconds. The call volumes between 2019 and 2021 did increase and may have been even higher for 2021 following CIS integration, if not for Enbridge Gas implementing enhanced web self-serve options, including an online chatbot in August 2019. From the time of integration in July 2021 to the end of that year, there were approximately 900,000 transactions completed across the digital channels (My Account, IVR and chatbot) which represents approximately half of total customer interactions which otherwise could have been calls to the call centre. The web self-service implementation is part of Enbridge Gas's digital strategy to better meet customer expectations. Enbridge Gas's customers can self-serve for less complex inquiries such as viewing account balances, submitting meter readings and moves. This leaves the more complex inquiries for the call centre, and these calls tend to be lengthier.

16. Complex call types are most often in the billing category and are driven by a heightened interest in understanding and lowering gas use and changes to rates, amplified by broader customer affordability concerns. These calls often include multiple intents within the same interaction. For example, a billing call may start with an inquiry about the balance but will commonly transition to options available to make payments easier if the balance is higher than expected. As well, during the initial pandemic period of 2020 through 2021, Enbridge Gas administered the Ontario Government's COVID-19 Energy

Assistance Program to support customers through pandemic lockdowns. Agents are trained to address customers' questions in an empathetic manner and offer support to customers experiencing hardship. The current metrics require agents to seek to minimize average call handle time so they can answer a higher volume of calls. A metric that incents shorter individual call times may result in a less positive customer experience for customers seeking assistance with paying bills and other complex issues.

2.3. Abandon Rate

17. AR tracks the percentage of callers who hang up while waiting for a live operator. The annual standard is not to exceed 10%. As a result of the increased call volume and call complexity, customers had a longer wait time to speak to a live operator and this impacted the AR. The 2021 result was 16.0%. As with the CASL measure, the 2021 result is not consistent with historical performance. The result in 2019 was 2.5% and 5.4% in 2020, exceeding the performance standard.

18. The AR was also impacted by the CIS integration in 2021 and the COVID-19 pandemic. The increase in call volumes, call handling time, and staffing issues due to illness resulted in an increase in wait times driving the increased AR.

2.4. Meter Reading Performance

19. MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% or less and Enbridge Gas attained 5.0% in 2021. The result for 2020 was 4.4% and 0.7% in 2019.

20. In 2019, the main reasons for Enbridge Gas not meeting the MRPM include:
    - Extreme weather events such as freezing rain, polar vortex, heavy snowfall and flooding which limited the ability to travel to properties and access meters safely; and

- A key vendor decision to no longer provide meter reading services and end its contract with Enbridge Gas, resulting in the unplanned need to hire a new vendor in an already limited market.

21. For 2020 and 2021, the pandemic presented many additional and unprecedented challenges to Enbridge Gas meeting the MRPM, such as:
    - Enbridge Gas, like all Ontario residents and businesses, was required to follow public health guidelines during the pandemic. During the early onset of the COVID-19 pandemic and periods of lockdown, Enbridge Gas faced several challenges with meter reading and considered pausing meter reading activity due to public concerns about the safety of meter reading activity. Enbridge Gas directed its meter reading partners to ensure that all staff were working as safely as possible and to avoid close contact with the public and customers based on sensitivities. The pandemic resulted in many events beyond the control of Enbridge Gas such as closed businesses, increased customer sensitivities and access issues such as the inability to read inside meters;
    - Extreme weather events such as freezing rain, polar vortex, heavy snowfall and flooding which limited the ability to travel to properties and access meters safety; and
    - A new meter reading vendor was still transitioning and learning the requirements of Enbridge Gas, while also facing challenges with staffing due to the COVID-19 pandemic. Resourcing issues impacted all meter reading vendors during the pandemic and included challenges hiring staff and absences due to illness and the quarantine/isolation periods required by public health to ensure public safety.

22. The attrition rate for meter reading personnel in 2022 is 20% and the level of absenteeism is 17%, the highest that Enbridge Gas has experienced. Meter reading vendors are also experiencing hiring challenges with low applicant interest due to the physically demanding nature of the role, which also contributes to the high attrition rate adding to the challenge of achieving the staffing levels required to meet the MRPM.

Weather is also an area where there is a shift to more natural weather events. In 2020 and 2021 there were over 27 different events ranging from flooding to tornadoes and severe cold and snow. Winter forecasts for 2023 call for snow, rain and record breaking cold temperatures which will contribute to missed reads due to unsafe weather conditions, particularly in the northern area. These changes in customer behaviour, labour market challenges and weather impacts that are outside of the control of Enbridge Gas are expected to continue for the foreseeable future. These factors make it unrealistic and impractical for Enbridge Gas to be able to commit to meeting the performance standard of 0.5% in future years.

23. In addition to the challenges listed above, the MRPM is cumulative, where the total number of unread meters fluctuates as some meters are read and are deducted from the totals, while other meters remain as unread from the previous month, and new meters reach their four-month timeline and are added to the current consecutive estimate results. This means that even though a percentage of meters have successfully been read, Enbridge Gas will continue to have meters that have consecutive estimates. With over 3.8 million customers, if 19,000 meters have consecutive estimates on average each month, the metric is not achieved. As noted above, having only one meter reader ill for ten business days leaves approximately 8,000 meters unread. The number of unread meters quickly increases with any number of unplanned absences.

24. Once a meter has consecutive estimates for four months or more, it will count toward the metric in a minimum of two meter reading cycles. Unread meters being carried into the next year compounds the results when added to the external challenges such as extreme weather events, COVID-19, and staffing issues. In addition, due to increased customer sensitivity, meter access issues are contributing in the range of 1-3% of the total monthly percentage of consecutive estimates. At the current metric level, based on access issues alone, Enbridge Gas is not able to meet the metric in 2022. The cumulative impact of all of these factors makes meeting the MRPM impossible for the year and that Enbridge Gas will enter 2023 in a deficit for meter reading.

25. Enbridge Gas is working with customers whose meters are not accessible. Examples include sending regular emails and letters asking the customers to submit a read (an option that is always available to customers), working with field staff to obtain reads on all service visits and sending out personnel to knock on customers' doors to arrange access to the meter. Enbridge Gas is also working with customers impacted by the consecutive estimates to ensure that their billing is reconciled as soon as an actual read is obtained. In addition, Enbridge Gas is sending out notices where an email is available to advise customers of the adjustments which include the adjusted amount, time frame and difference in charges. Enbridge Gas issues customer bills (paper and eBill) 21 days before payment is required, providing customers with the opportunity to contact Enbridge Gas regarding any concerns about their amount owing. Where the billing adjustment results in an amount owing, flexible pay arrangements are offered in the event that they need extra time to pay. Where the billing adjustment results in a credit, customers have the option for Enbridge Gas to return the amount owing to them automatically through their bank, an interac etransfer or a cheque.

26. Enbridge Gas is continuing work to maintain and, where necessary, improve the results of all scorecard performance measures through ongoing reporting of results, identifying the root cause for variances and implementing initiatives targeting areas where improvement can be made. Such initiatives include the implementation of automated process tools which allow Enbridge Gas to process reads into its system faster making them available for billing to customers. Enbridge Gas is committed to continuous year over year performance improvement and has developed mitigation plans to aid in achieving progress.

2.5. Time to Reschedule a Missed Appointment

27. The TRMA tracks the percentage of customers contacted to reschedule work within two hours of the end of the original appointment time. Enbridge Gas has historically experienced challenges meeting the annual performance standard of 100% for the TRMA measure. The result in 2021 was 97.0%, consistent with previous years.

28. Efforts toward improving the TRMA target of 100% are ongoing. Enbridge Gas began to align work management systems and processes upon amalgamation, in 2019 and by 2021, was able to move to one platform for the planning and scheduling of customer work. Enbridge Gas is investigating process and technology solutions that will further enhance its ability to reschedule customer appointments when required. For example, technology to ensure technicians can continue to use their cellular phones in the event of a service provider outage has been implemented and the ability to text customers to communicate that they will not be able to attend the appointment on time are being reviewed.

29. While Enbridge Gas acknowledges that prompt rescheduling of missed appointments is an important part of achieving the SQRs and customer service, attainment of a performance standard of 100% is unreasonable and impractical. The 100% target does not consider factors like emergency response, human error and technical error. In the event of an emergency, technicians and dispatch team members are redirected from non-emergent customer appointments to respond to emergencies such as blowing gas or an odour call. Redirecting from customer appointments to respond to an emergency can impact the ability of Enbridge Gas to meet a booked customer appointment and the reschedule timeline. It should be noted that the number of missed appointments that are not rescheduled within the required time represents a small percentage of total customer four-hour window appointments. For example, in 2021 there were 54 four-hour window appointments that were missed and the customer was not contacted to rescheduled within two hours of the original appointment window end time. 54 appointments represents 0.1% of the 51,821 four-hour window appointments completed in 2021. Of the 54 appointments where Enbridge Gas did not contact the customer to reschedule within two hours of the original appointment window, there were 20 appointments that were still completed that day. In addition, Enbridge Gas consistently exceeds the Appointments Met target, demonstrating commitment to and success with overall customer service. By meeting more appointments, the Company reduces the absolute number of calls that require rescheduling, which promotes greater customer satisfaction.

3. Exemption Request and GDAR Review Recommendation

30. Enbridge Gas anticipates continued challenges meeting the existing performance standards in 2023 for the CASL, MRPM and TRMA and therefore is seeking a partial exemption from these SQR measures from January 1, 2023 to December 31, 2023. Mitigation plans have been developed and initiatives are being implemented to improve performance, however, given continuing pandemic-related impacts, changes in customer behaviour and expectations and comparisons with the equivalent performance standards for electric utilities, the existing targets are no longer reasonable. Enbridge Gas requests a partial exemption from CASL, MRPM and TRMA to be replaced by modified measures set out in Attachment 2 to this Application and summarized as follows:
    - CASL – achieve 65% of calls reaching the general inquiry number answered within 30 seconds. This aligns with the DSC;
    - MRPM – achieve no more than 2% of meters with consecutive estimates for four months or more; and
    - TRMA – attempt to contact customers requiring a rescheduled appointment within one business day of the original appointment window 98% of the time. This is also similar to the DSC.

    Enbridge Gas aims to meet the AR measure of no more than 10% of callers hanging up while waiting for a live operator and is not asking for any form of exemption from the AR.

31. In the longer term and for the purpose of generic application to rate-regulated gas utilities, Enbridge Gas recommends that the OEB's Chief Executive Officer conduct a review of the GDAR pursuant to Section 44 of the *Ontario Energy Board Act* and consider appropriate amendments to CASL, MRPM and TRMA.

32. Enbridge Gas submits that a generic review of the GDAR performance standards is required because:
    - the performance standards were established more than 15 years ago and are not reflective of the current customer behaviours and expectations. For instance,

customer calls are more complex in nature as customers can use web self-service options and chatbot feature for less complex inquires;

- there is lack of alignment with the DSC performance standards and no allowance for force majeure relief in the GDAR;
- there are continuing impacts of external factors such as the pandemic, labour market and economic environment; and
- planned activities to align systems and meet industry standards (such as for cyber-security) may impact SQR performance.

3.1. Customer Behaviour and Expectations

33. The SQRs were added to the GDAR on January 1, 2007. The SQR performance measures are more than 15 years old and in that time, there have been notable changes to customer behaviour and expectations. From the customer behaviour perspective, there is increased customer sensitivity to contact with meter readers and/or meter readers going onto homeowners' property which creates access issues. In addition, since the pandemic began, more customers are working from home and are now seeing readers access the meter which is causing increased customer concerns such as trespassing and accusations of meter readers stealing packages from front porches. From the customer expectation perspective, customers expect digital channels in addition to being able to reach agents by phone by calling the call centre. Companies now need to develop, support, and maintain service levels for multiple points of contact for customers. Digital channels such as websites, chatbots and IVRs allow customers to complete self-serve activities such as change of address and checking account information.

3.2. Distribution System Code Alignment

34. The DSC performance requirements and the SQRs within the GDAR do not align on similar measures. Referenced DSC provisions are set out in Attachment 3.

- Rescheduling a Missed Appointment measure in the DSC is an attempt to contact the customer prior to the appointment and an attempt to reschedule within one business day compared to the GDAR requirement to reschedule within two hours of the end of the original appointment time;

- The Telephone Accessibility performance measure in the DSC is to answer 65% of calls in 30 seconds compared to CASL in the GDAR that requires 75% of calls to be answered in 30 seconds; and
- The DSC contains a force majeure provision that allows a utility to be relieved of obligations for events that are beyond its reasonable control and the GDAR is silent on force majeure.

3.3. External Factors and Planned Activities

35. External factors such as the pandemic, labour market conditions and economic factors continue to impact the ability of Enbridge Gas to meet the performance standards outlined in the GDAR. Mitigation plans have been developed and initiatives are being implemented that will assist the Company in managing outside factors; however the Company expects continued challenges with meeting existing targets. Outside factors include:
    - The COVID-19 pandemic continues to impact the ability to meet performance standards with increased illness and absence of call centre agents and meter readers;
    - Challenges hiring staff experienced across Ontario has impacted the ability to hire temporary and full-time employees for the call centre and for the meter reading vendor to hire full-time staff;
    - Extreme weather events such as heavy snowfall, extreme cold, and flooding have been impactful, and this trend is likely to continue; and
    - An increase in the natural gas market price, due to inflation, global energy shortages and federal carbon charges have resulted in an increase in customer bills resulting in an increase in calls to the call centre.

36. As explained above, the increased complexity of calls has led to longer call times which impacts the number of calls that can be answered by agents. Agents typically manage

multiple questions with each customer transaction with the majority of questions being about billing including how to lower usage, questions about changes to rates and affordability concerns. The focus on decreasing call handling time to meet the metric target can result in a less positive customer experience as agents work to quickly answer inquiries and move to the next call rather than taking extra time when needed to understand the entire customer experience, address concerns and respond in an empathetic manner.

4. Mitigation Plans

37. Enbridge Gas is committed to providing excellent customer service to all customers and has developed mitigation plans for the performance measures for which we are seeking relief in 2023. The mitigation plans outlining the approach to improve CASL, MRPM and TRMA performance in 2023 and throughout the rebasing period are provided at Attachments 4 through 6 to this Application.

4.1. CASL and AR Mitigation

38. To improve performance on the CASL and the AR, Enbridge Gas has identified and implemented several initiatives outlined in the mitigation plan provided at Attachment 4. The main elements include:

- Planning – implementing an augmented planning process to better assess and mitigate impacts from events with customer-facing impacts.
- Resourcing – recruiting temporary and full-time employees to assist with high call volumes at all call centre and billing locations;
- Digital Channel Enhancements – review and continuous improvement of systems to enhance customer experience; and
- Customer Service Processes – continuous improvement in response to customer surveys and internal reviews.

39. The mitigation plans aim to achieve as close to the existing CASL performance standard as possible, however given the uncertainty of continuing pandemic-related impacts and

other factors noted above, Enbridge Gas is uncertain about whether it can achieve CASL for 2023. Also, alignment with the DSC is appropriate for CASL.

4.2. MRPM Mitigation

40. Enbridge Gas recognizes the importance of obtaining regular meter reads and is committed to implementing a plan to reduce the consecutive estimate count. Key initiatives are outlined in the mitigation plan provided at Attachment 5. The main elements include:
    - Consecutive estimate campaign – working with meter reading vendors to hire additional readers and conduct spring reading and communication campaigns;
    - Inbound calls – educating customers on the importance of providing access to meters and providing assistance to read own meters;
    - Customer outreach – targeted customer communications to engage customers to arrange for meter access and submit own meter reads;
    - Operations engagement – field operations to support meter access efforts; and
    - Meter reading processes – review and continuous improvement to increase attainment and efficiency.

41. The mitigation plan aims to achieve a 2% MRPM commencing in 2023.

42. In addition to the above-mentioned initiatives to reduce the consecutive estimate count, Enbridge Gas is investigating an Advanced Metering Infrastructure (AMI) solution to automate its meter reading process for customers. Details on this initiative will be included in the 2024 Rebasing Application. The current meter reading process is highly manual and can be inconvenient to customers. Further, the utility industry is overwhelmingly moving towards some form of meter automation, leading to changes in both market conditions and customer expectations. Automation is more accurate and convenient for customers while allowing operational efficiencies to be achieved for the utility and additional insight for customers as they can see further details on their gas consumption patterns.

4.3. TRMA Mitigation Plan

43. To improve performance on TRMA, Enbridge Gas has identified several initiatives outlined in the mitigation plan provided at Attachment 6. The main elements include:

- Process – align existing processes for identifying attempts to contact the customer to reschedule appointments;
- Technology – leverage technology to aim to improve performance measure results through additional customer contact options for appointment rescheduling;
- Reporting - enhanced reporting of results and corrective action process; and
- Communication – ongoing communication of process to reschedule appointments.

44. The mitigation plans aim to achieve a performance standard of 98% of customer appointments rescheduled within one business day for TRMA commencing in 2023.

4.3. Mitigation Plan Monitoring and Conditions of Approval

45. Enbridge Gas will monitor the success of the mitigation initiatives and the impact on metric performance to determine if adjustments need to be made to the initiatives or if new initiatives need to be added. Internally, weekly reporting and comprehensive monthly reviews will occur with the cross-functional teams responsible for metric performance. Monthly reviews will include variance explanations and management action plans focusing on continuous improvement. In addition, monthly reporting of mitigation plan progress and metric performance will be presented to Enbridge Gas senior leadership.

46. Enbridge Gas anticipates the continuation of annual SQR reporting under the *Natural Gas Reporting and Record Keeping Requirements (RRR) Rule for Gas Utilities* during the relief period. Enbridge Gas will also provide quarterly updates to OEB staff on its progress with implementing mitigation plans and metric performance for CASL, MRPM and TRMA.

5. Summary

47. Enbridge Gas hereby applies to the OEB, pursuant to section 1.5.1 of the GDAR, for a partial exemption for a period of one year, from January 1, 2023 to December 31, 2023, from the following SQRs in GDAR:
    a. subsection 7.3.1.1 CASL performance standard of 75%, to be revised to 65%;
    b. subsection 7.3.3.1 MRPM performance standard of not exceeding 0.5%, to be revised to not exceeding 2%; and
    c. subsection 7.3.4.2 TRMA performance standard of 100%, to be revised to meeting a target of 98%.

48. Enbridge Gas further applies to the OEB for all necessary orders and directions concerning pre-hearing and hearing procedures for the determination of this application.

49. Enbridge Gas requests that the OEB's review of this application proceed by way of written hearing in English.

50. Enbridge Gas requests that all documents relating to this application and its supporting evidence, including the responsive comments of any interested party, be served on Enbridge Gas as follows:

The Applicant:

Attention: Tania Persad
Associate General Counsel, Regulatory Law

Address: Enbridge Gas Inc.
500 Consumers Road
North York, Ontario
M2J 1P8

Telephone: (416) 495-5891
Fax: (416) 495-5994
Email: tania.persad@enbridge.com

and

Lesley Austin
Advisor Regulatory Applications
Regulatory Affairs

Address: Enbridge Gas Inc.
500 Consumers Road
North York, Ontario
M2J 1P8

Telephone: (416) 495-6505
Email: lesley.austin@enbridge.com
egiregulatoryproceedings@enbridge.com

Dated: October 27, 2022

Enbridge Gas Inc.

Tania Persad Digitally signed by Tania Persad
Date: 2022.10.27 13:57:58
-04'00'

Tania Persad
Associate General Counsel, Regulatory Law

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL Tanya.Mushynski@enbridge.com

January 27, 2023

Tanya Mushynski
Vice President, Customer Care
Enbridge Gas Inc.
500 Consumers Road
North York ON

Dear Ms. Mushynski:

Re: Enbridge Gas Inc. Service Quality Requirements Performance 2022

On September 15, 2022, the Ontario Energy Board (OEB) accepted an Assurance of Voluntary Compliance (AVC) from Enbridge Gas Inc. (Enbridge) regarding Enbridge's compliance with certain of its service quality requirements (SQRs) as set out in the Gas Distribution Access Rule (GDAR). In the AVC, Enbridge acknowledged it had not met certain SQRs and committed to mitigation plans that aimed to:

- Achieve call answer performance measures (CAPM) of 75% of calls answered within 30 seconds, with a minimum monthly standard of 40% and, a call abandon rate not to exceed 10%.

- Achieve an improved meter reading performance metric of 4% for 2022 (SQR target is 0.5%)

In accordance with the provisions of the AVC, Enbridge is providing monthly updates on its SQR performance to OEB staff. On January 16, 2023, Enbridge submitted a final report on the 2022 year-end status for each metric as follows:

- Abandon rate: 7.1%
- Call answering service level: 75.94%
- Meter reading performance: 4.1%

While Enbridge exceeded the call answer and abandon rate targets, it is noted that, while close, the target for improved meter reading performance was not met.

On December 23, 2022, I wrote to Enbridge indicating that OEB staff did not intend to commence a compliance action against Enbridge related to the above noted SQR provisions of the GDAR pending a final decision on Enbridge's exemption request in the EB 2022-0200 proceeding. In turn, OEB staff expressed its expectation that Enbridge continue to meet the commitments it made in relation to SQRs in the AVC and, in relation to time to reschedule missed appointments, to meet the requirement set in GDAR.

It is acknowledged that Enbridge has made progress in improving its call answer service level and abandon rate. However, OEB staff expect to see additional improvement in meter reading performance to ensure Enbridge is meeting its commitments in the AVC. Enbridge is also expected to continue to provide monthly scorecard performance updates.

Should you have any questions relating to this letter, please contact Donna Kinapen by e-mail at donna.kinapen@oeb.ca or on her mobile at 416-817-5930.

Sincerely,

Brian Hewson
Vice President, Consumer Protection & Industry Performance

c.c. Mark Kitchen - mark.kitchen@enbridge.com

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

February 14, 2023

By email: Brian.Hewson@oeb.ca

Brian Hewson
Vice President, Consumers Protection & Industry Performance
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Brian Hewson:

Re: Enbridge Gas Inc. Service Quality Requirements Performance 2022

On January 27, 2023, we received your letter regarding the Ontario Energy Board (OEB) staff review of the Service Quality Requirement (SQR) performance of Enbridge Gas Inc. (Enbridge Gas) for 2022. The letter acknowledges the progress that Enbridge Gas has made in its call answer service level and abandon rate and noted that OEB staff expects to see additional improvement in meter reading performance to ensure Enbridge Gas is meeting its commitments in the Assurance of Voluntary Compliance (AVC).

Enbridge Gas reaffirms our commitment to continuing to improve our performance on the Meter Reading Performance Metric (MRPM). In the AVC, Enbridge Gas committed to MRPM mitigation plans that aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). For 2022, Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% or 2.5% when accounting for meters that Enbridge Gas could not access. These results exceeded the AVC commitment when accounting for meters where access is limited by the customer.

At the end of 2022, Enbridge Gas had 1.2% (approx. 46k) of customers with consecutive estimates, down from 9% (approx. 347k) in March, following weather and resource challenges in Q1. To continue to improve our MRPM performance, Enbridge Gas is carrying on with the actions outlined in our mitigation plan and we are maintaining an increased focus on meters with access issues. We believe that these actions will result in an MRPM for 2023 that trends downwards from the 4%/3% AVC commitment for 2022.

OEB Staff has also noted the expectation that Enbridge Gas meet the SQR for Time to Reschedule Missed Appointments (TRMA) of 100%. As we've explained in our evidence for the SQR exemptions, Enbridge Gas continues mitigation work to improve results, however the TRMA metric remains challenging as it does not consider factors like emergency response, human error and technical error. While Enbridge Gas acknowledges that prompt rescheduling of missed appointments is an important part of achieving the SQRs and customer service, it should be noted that the number of missed appointments not rescheduled within the required time represents a small percentage of total customer four-hour appointments (.1% in 2021, impacting 54 customers). Additionally, Enbridge Gas consistently exceeds the Appointments Met target, demonstrating commitment to and success with overall customer service.

Enbridge Gas will continue to provide monthly updates to OEB Staff as committed to in the AVC. Should you have any questions, please do not hesitate to contact me by e-mail at Tanya.Mushynski@enbridge.com or by phone at 416-495-5007.

Sincerely,

Tanya Mushynski
Vice President, Customer Care

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 7, Schedule 1, p. 14; EB-2022-0188 Enbridge Gas Assurance of Voluntary Compliance, dated September 12, 2022

Question(s):

The CASL performance standard as set out in GDAR is 75% of calls reaching the general inquiry number answered within 30 seconds. Aside from 2021 where Enbridge Gas achieved 64.3% in this performance measure, Enbridge Gas has historically achieved the target. Enbridge Gas requested to modify its CASL performance measure from 75% to 65%.

In September 2022, Enbridge Gas provided the OEB with an Assurance of Voluntary Compliance in which it committed to mitigation plans that aim to achieve 75% for the CASL performance measure for 2022.

Please explain the basis for modifying the CASL measure from 75% to 65% given that aside from 2021, Enbridge Gas has historically achieved the metric and has committed to mitigation plans to achieve the 75% CASL measure for 2022.

Response:

Enbridge Gas has taken all reasonable steps in striving to achieve the CASL targets on a consistent basis and will aim to achieve the metrics in 2023. Enbridge Gas is requesting an exemption of the CASL measure as part of its proposal to modernize certain SQRs to meet the current business environment, customer needs, behaviours and expectations. The request aims to achieve a balance between providing a high level of customer service and the cost to customers.

Enbridge Gas has requested an exemption for CASL whereby the target would provide a high level of performance and customer service while at the same time align with the electric utilities' metric of 65% as discussed in evidence at Exhibit 1, Tab 7, Schedule 1, page 16.

Through the implementation of several forecasting, process and system changes as well as hiring of additional staff, Enbridge Gas was able to meet the CASL metric for 2022. Even though Enbridge Gas achieved this metric an increasing trend in call complexity means that Enbridge Gas cannot answer as many calls in the 30 second CASL requirement. The focus on decreasing call handling time can result in a less positive customer experience as the agent works quickly to answer inquires and move to the next call rather than taking additional time to understand the entire customer experience. This proposal would allow the Enbridge Gas agents additional time resulting in better customer service as provided at Exhibit 1, Tab 7, Schedule 1, page 18.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 7, Schedule 1, Attachments 2-4

Question(s):

Enbridge Gas's mitigation plans for 2022 were provided to the OEB as part of the Assurance of Voluntary Compliance dated September 2022; the mitigation plans for the 2023 reporting year were provided in Enbridge Gas's 2023 GDAR Exemption Request Application (EB-2022-0276); and the mitigation plans for 2024 and beyond were filed as part of the current application.

Please provide an update on the implementation of Enbridge Gas's mitigation plans to date. Describe what mitigation plan(s) have been implemented, its outcome(s), and how it has impacted Enbridge Gas's performance metric(s) for 2022.

Response:

Enbridge Gas is committed to providing excellent customer service to all customers and has developed mitigation plans for the performance measures not met in 2021. The Company aims to achieve the expected performance standards however, recognizes there is a balance between achieving the metrics, providing a positive customer experience, and the cost to customers.

Call Answering Service Level (CASL), Abandon Rate (AR) and Meter Reading Performance Metric (MRPM)

Enbridge Gas has implemented all aspects of the mitigation plans set out in the 2022 Assurance of Voluntary compliance (AVC). Mitigation plans for 2023 and 2024 are an extension of the 2022 plans. In relation to the AVC, Enbridge Gas has submitted monthly reports to OEB Staff which commenced in October 2022. Please see Attachments 1 to 4 for the monthly reports.

Enbridge Gas met both the CASL and the AR metrics in 2022. As set out in the AVC[1], Enbridge Gas agreed to aim for a target of 4% (or 3% excluding meters where access is not granted by customers) for the MRPM. The MRPM result for 2022 was 4.1% (and 2.5% for meters where access was not granted by customers).

Time to Reschedule a Missed Appointment (TRMA)

An updated process outlining the steps to contact the customer when a rescheduled appointment is required has been developed. The process includes a method for identification of an attempt made to contact the customer. In addition, a process to report missed reschedules, the reason for the miss, and escalated management action plans have been developed. Updated processes will be communicated in Q1 2023 and will continue to be reinforced. These efforts, along with potential future technology enhancements towards meeting the TRMA target are ongoing, however, Enbridge Gas does not anticipate meeting the 100% performance standard. Attainment of a perfect 100% does not consider factors like emergency response, human error or technical error.

[1] EB-2022-0188, Assurance of Voluntary Compliance, Enbridge Gas Inc. September 12, 2022. EGI-Assurance-of-Voluntary-Compliance-20220912.pdf (oeb.ca)

ENBRIDGE

memo

Date: October 14, 2022

To: Brian Hewson, Vice President Consumer Protection & Industry Performance, OEB

From: Tracy Lynch, Director Customer Care Operations, EGI

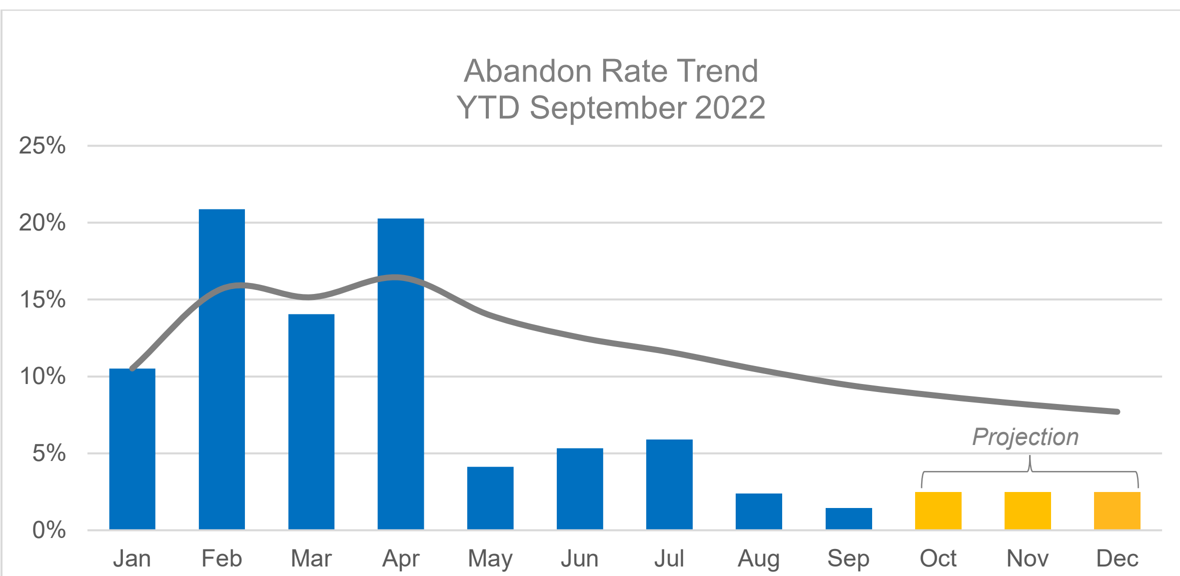
cc: Richard Lanni, Senior Legal Counsel, Legal Services, OEB
Donna Kinapen, Manager, Consumer Policy & Compliance, OEB

Re: **Service Quality Requirements (SQR): Abandon Rate, Call Answering Service Level, Meter Reading Performance Measurement**

As part of the Assurance of Voluntary Compliance (AVC) filed on September 14, 2022, Enbridge Gas committed to providing monthly reporting to OEB staff on the progress of the SQR metrics. Below is a summary of the status of each metric as of September 30, 2022.

Abandon Rate

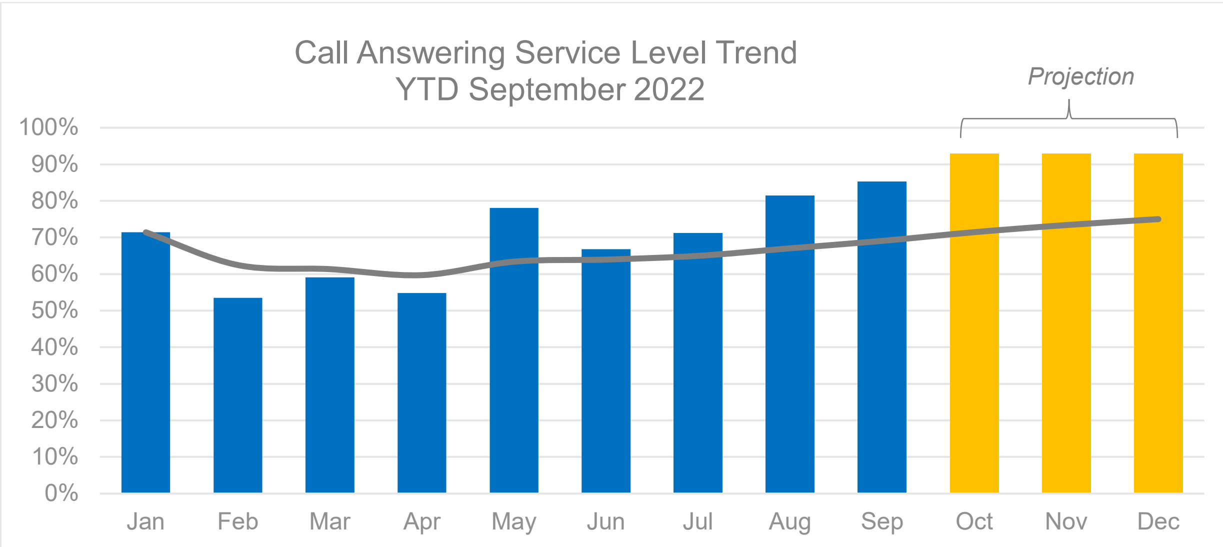
Abandon Rate (AR) tracks the percentage of callers who hang up while waiting for a live operator. The annual standard is not to exceed 10%. The September 2022 year to date result is 9%. Enbridge Gas anticipates that AR will be achieved in 2022.



ENBRIDGE

Call Answering Service Level

Call Answering Service Level (CASL) tracks the percentage of calls reaching the general inquiry number, including IVR calls that are answered within 30 seconds. The yearly performance standard for CASL is 75% with a minimum monthly standard of 40%. The September 2022 year to date result is 69%. Enbridge Gas is continuing to work diligently through implementation of its mitigation plan as outlined in the AVC to aim to achieve CASL for 2022.



Mitigation Activities

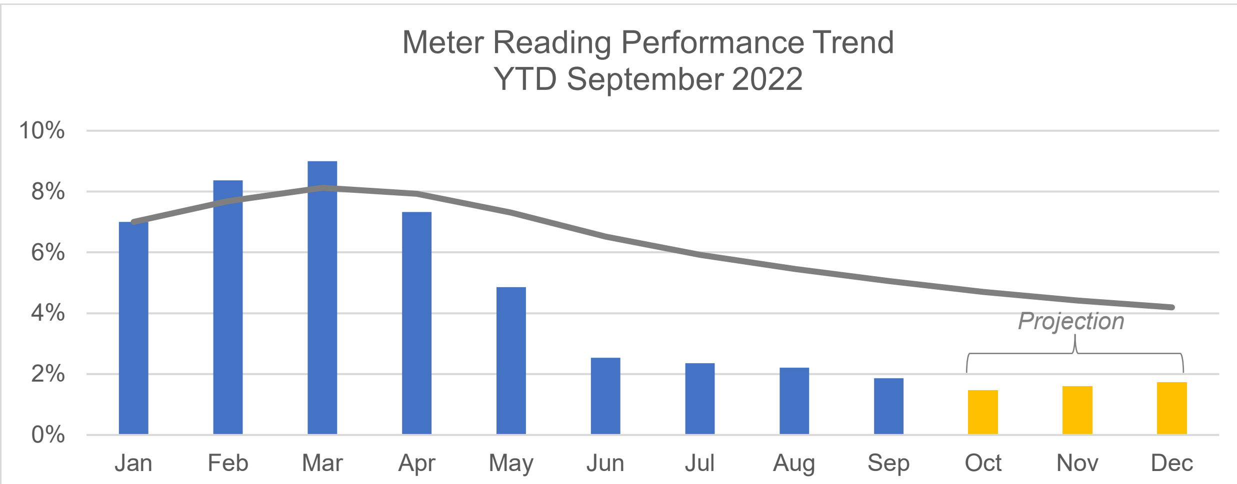
- Additional staff hired and calls are being answered faster, the average speed to answer a customer's call in early 2022 was over 10 minutes, this has improved and in Q3 2022 customers are waiting less than 90 seconds on average. In addition, in Q3, 79% of calls have been answered within 30 seconds.
- Proactive customer comunications to promote use of self-serve digital channels for less complex transactions.
- Continue to hire full-time and temporary staff to assist with high call volumes at all call centre locations (additional 65 call centre agents to start in October/November).
- Improve processes to assist with customer experience, for example, a call back option is currently being piloted in which customers are provided with an option to have a call back rather than waiting for a live agent.
- Focus on employee engagement activities to promote mental wellness and retention.

Challenges

- Call volumes continue to be higher as a result of trending call types including rate increases, managing equal monthly payment plans, collections, and an increase in customer moves.
- Illness and absenteeism continue to be a challenge. Historical average illness and absenteeism rate from 2019 to 2021 has been up to 10%. In 2022, due to an increasing trend of mental health related incidents in conjunction with COVID, illness absence rates have more than doubled. The Enbridge contact centre recently experienced a covid-related event in which 27% of the workforce was ill for a period of two weeks.
- Higher attrition rates and hiring challenges continue due to the tight labour market.

Meter Reading Performance Measurement

Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the MRPM is 0.5% or less. As stated in the AVC Enbridge Gas anticipates MRPM to be in the range of 4% (or 3% if we exclude meters where access is not granted by customers). The September 2022 year to date result is 5% (3% when meters with access issues are removed). Enbridge Gas is continuing to work diligently through implementation of its mitigation plan as outlined in the AVC and aims to achieve this revised MRPM for 2022.



Mitigation Activities

- Working with internal staff and third party vendors to assist with attaining reads to offset attrition and absenteeism impacts.
- Continue to hire resources to mitigate increased absences.
- In addition to monthly emails, letters were mailed to customers encouraging them to submit a read (80K notices sent out between the two channels).
- Marketing campaign on social media promoting the Win Free Gas campaign.[1]
- Meter readers are working overtime, including evenings and weekends to attain reads.
- Additional back office staff being hired to process reads coming in, 10 agents started in August with 20 additional agents starting in October.

Challenges

- Attrition and illness/absense continue to be a challenge. Year to date attrition rates are 20% and absenteeism rates are 17%.
- Hiring challenges continue due to the tight labour market.
- Ongoing access issues: 50% of our current consecutive estimates are due to access limited by customers.

[1] "Submit your meter reading to win Free* natural gas for a year!" contest. The contest ran between June 15 – September 30, 2022. *Customers submit a meter reading for a chance to with $2000 each. Three prizes of $2000 each was awarded. Contest provided details on how to read a meter, submit a meter reading, a reminder not to block the meter from view, safety tips, question & answer section, and the contest rules and regulations.

memo

Date: November 16, 2022

To: Brian Hewson, Vice President Consumer Protection & Industry Performance, OEB

From: Tracy Lynch, Director Customer Care Operations, EGI

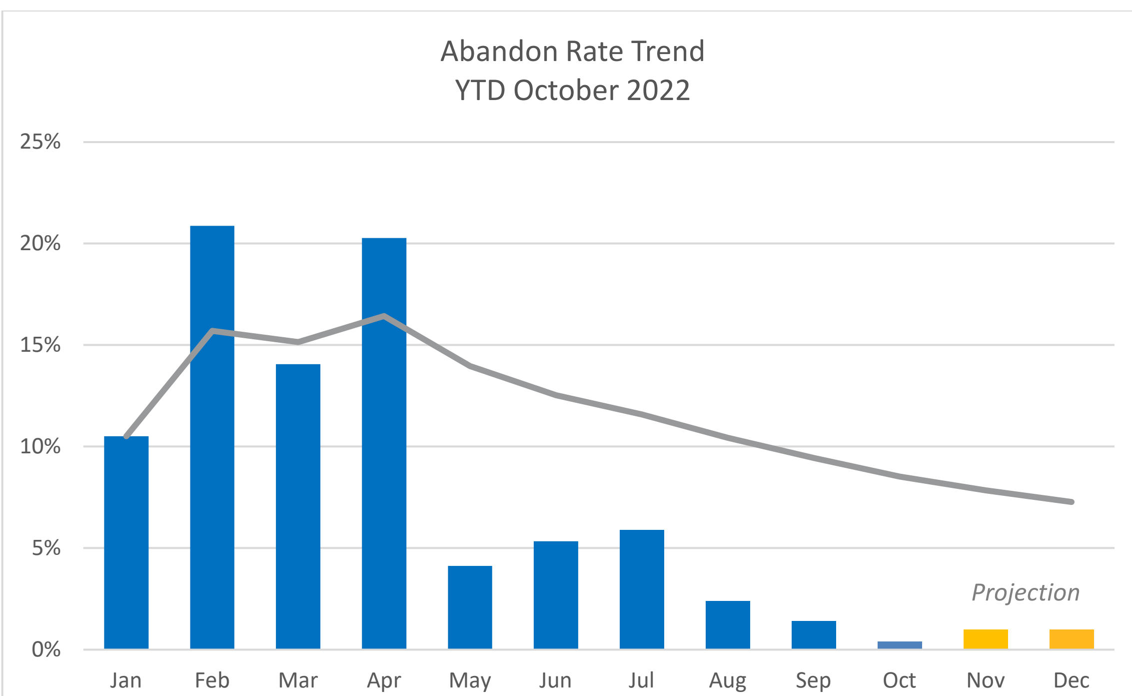
cc: Richard Lanni, Senior Legal Counsel, Legal Services, OEB
Donna Kinapen, Manager, Consumer Policy & Compliance, OEB

Re: Service Quality Requirements (SQR): Abandon Rate, Call Answering Service Level, Meter Reading Performance Measurement

As part of the Assurance of Voluntary Compliance (AVC) filed on September 14, 2022, Enbridge Gas committed to providing monthly reporting to OEB staff on the progress of the SQR metrics. Below is a summary of the status of each metric as of October 31, 2022.

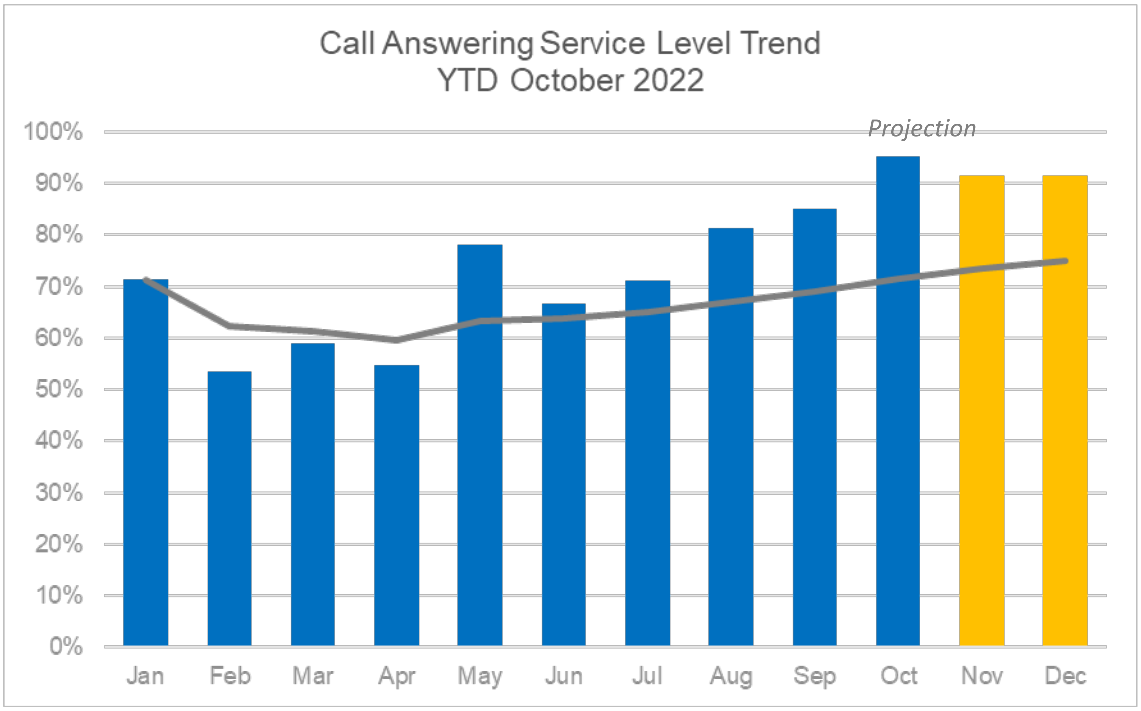
Abandon Rate

Abandon Rate (AR) tracks the percentage of callers who hang up while waiting for a live operator. The annual standard is not to exceed 10%. The October 2022 year to date result is 8%. Enbridge Gas anticipates that AR will be achieved in 2022.



Call Answering Service Level

Call Answering Service Level (CASL) tracks the percentage of calls reaching the general inquiry number, including IVR calls that are answered within 30 seconds. The yearly performance standard for CASL is 75% with a minimum monthly standard of 40%. The October 2022 year to date result is 72%. Enbridge Gas is continuing to work diligently through implementation of its mitigation plan as outlined in the AVC to aim to achieve CASL for 2022.



Mitigation Activities

- Hiring and training of new staff to assist with high call volumes at all call centre locations.
- Proactive planning for customer communications including emails for the "Notice of Hearing for Enbridge Gas's application for 2024 Cost of Service Rates" to assist with a potential increase in call volumes.
- Improve processes to assist with customer experience including a call back option which has been implemented in which customers are provided with an option to have a call back rather than waiting for a live agent.
- Focus on employee engagement activities to promote mental wellness and retention.

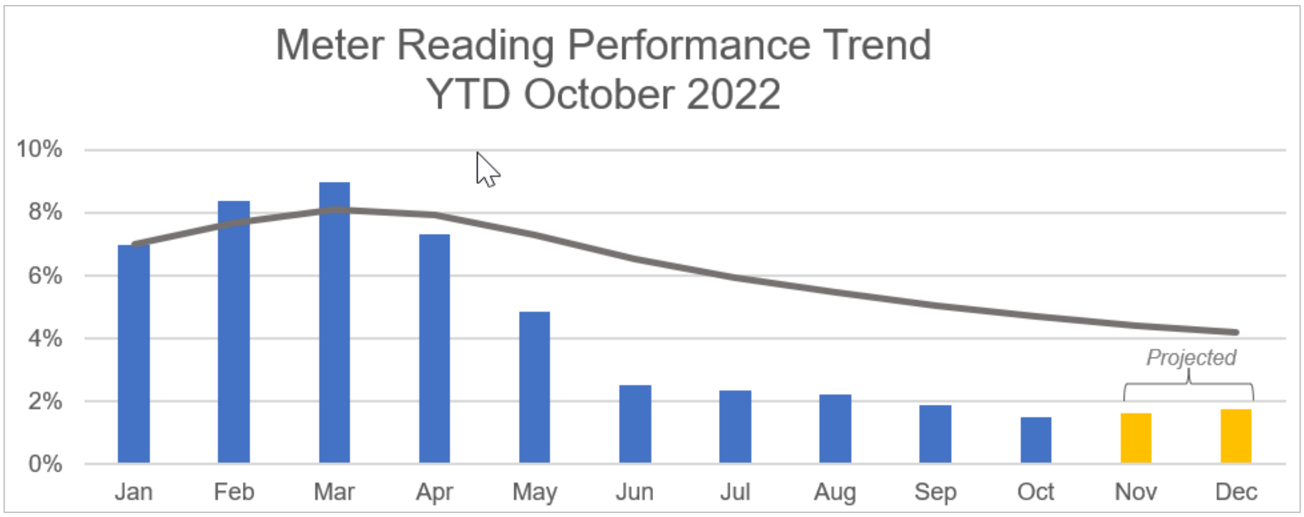
Challenges

- Call volumes continue to be higher as a result of trending call types including rate increases, managing equal monthly payment plans, collections, and an increase in customer moves.
- Illness and absenteeism continue to be a challenge and is being closely monitored.
- Higher attrition rates and hiring challenges continue due to the tight labour market.

ENBRIDGE

Meter Reading Performance Measurement

Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the MRPM is 0.5% or less. As stated in the AVC Enbridge Gas anticipates MRPM to be in the range of 4% (or 3% if we exclude meters where access is not granted by customers). The October 2022 year to date result is 4.7% (2.8% when meters with access issues are removed). Enbridge Gas is continuing to work diligently through implementation of its mitigation plan as outlined in the AVC and aims to achieve this revised MRPM for 2022.



Mitigation Activities

- Continue working with internal staff and third-party vendors to assist with attaining reads to offset attrition and absenteeism impacts.
- Continue to hire resources to mitigate increased absences. Since March, 21 additional resources hired.
- Daily emails continue to be sent out encouraging customers to submit a reading.
- Meter readers continue to work overtime, including evenings and weekends to attain reads.
- Additional back office staff being hired to process reads coming in, 10 agents started in August and 20 additional agents started in October.

Challenges

- Attrition and illness/absence continue to be a challenge. Year to date attrition rates are 20% and absenteeism rates are 17%.
- Hiring challenges continue due to the tight labour market.
- Ongoing access issues: 50% of our current consecutive estimates are due to access limited by customers.

memo

Date: December 19, 2022

To: Brian Hewson, Vice President Consumer Protection & Industry Performance, OEB

From: Tracy Lynch, Director Customer Care Operations, EGI

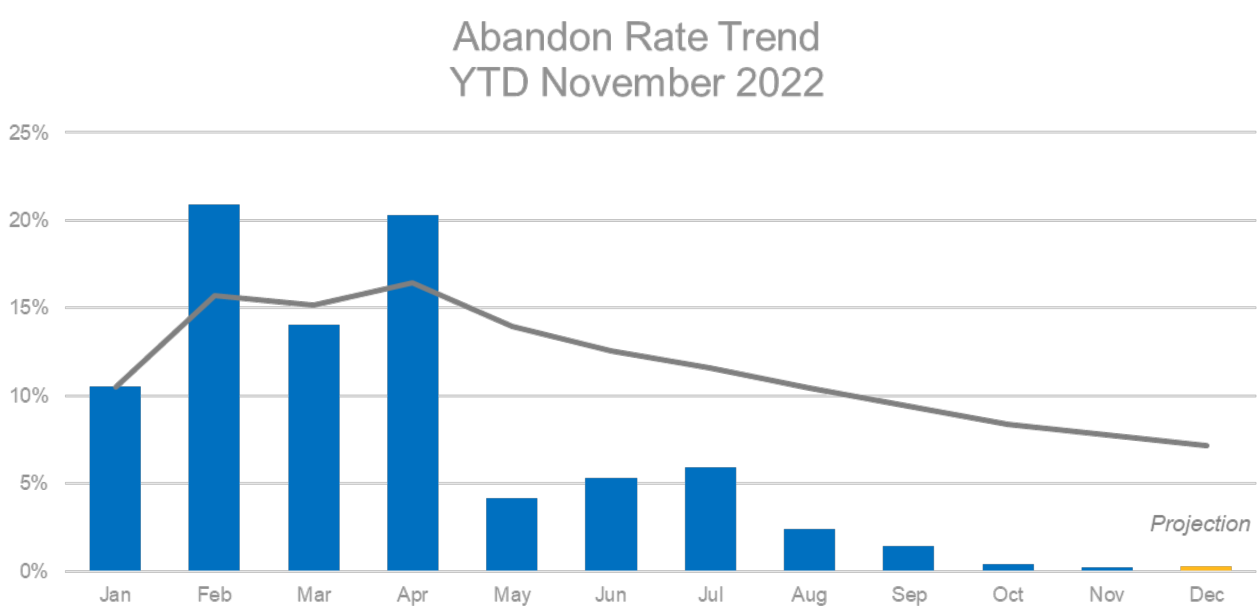
cc: Richard Lanni, Senior Legal Counsel, Legal Services, OEB
Donna Kinapen, Manager, Consumer Policy & Compliance, OEB

Re: **Service Quality Requirements (SQR): Abandon Rate, Call Answering Service Level, Meter Reading Performance Measurement**

As part of the Assurance of Voluntary Compliance (AVC) filed on September 14, 2022, Enbridge Gas committed to providing monthly reporting to OEB staff on the progress of the SQR metrics. Below is a summary of the status of each metric as of November 30, 2022.

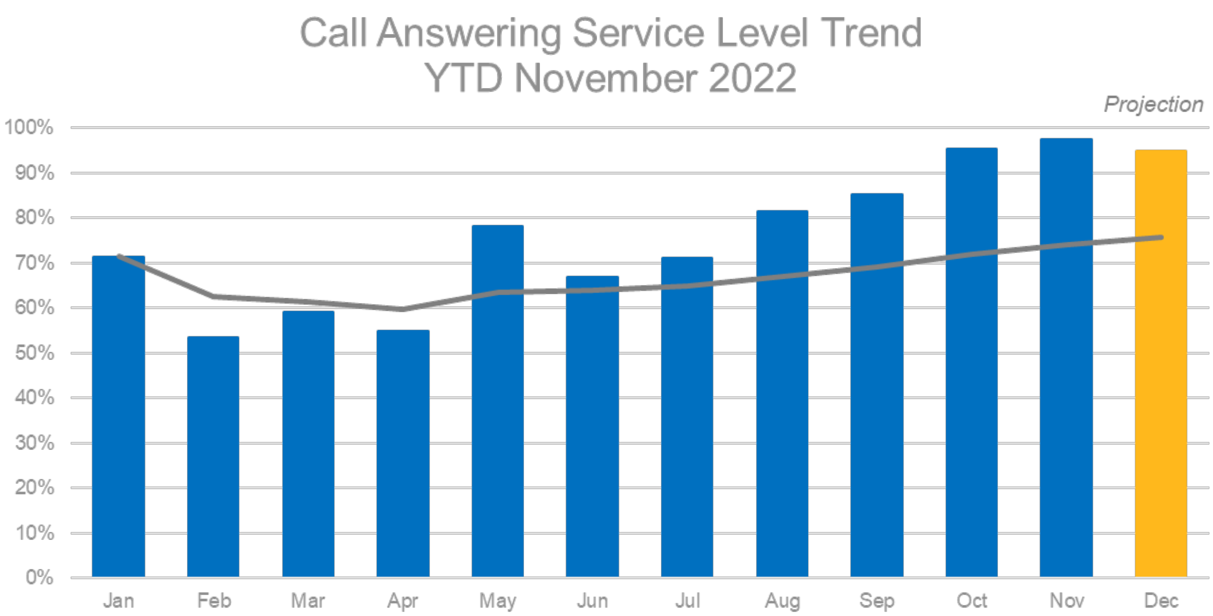
Abandon Rate

Abandon Rate (AR) tracks the percentage of callers who hang up while waiting for a live operator. The annual standard is not to exceed 10%. The November 2022 year to date result is 8%. Enbridge Gas anticipates that AR will be achieved in 2022.



Call Answering Service Level

Call Answering Service Level (CASL) tracks the percentage of calls reaching the general inquiry number, including IVR calls that are answered within 30 seconds. The yearly performance standard for CASL is 75% with a minimum monthly standard of 40%. The November 2022 year to date result is 74%. Enbridge Gas is continuing to work diligently through implementation of its mitigation plan as outlined in the AVC to aim to achieve CASL for 2022.



Mitigation Activities

- Ongoing hiring and training of new staff to assist with high call volumes at all call centre locations.
- Proactive planning for customer communications on key information to assist with call volumes.
- Focus on employee engagement activities to promote mental wellness and retention.

Challenges

- Call volumes continue to be higher as a result of trending call types including rate increases, payment plans, and early heating season inquiries.
- Illness and absenteeism continue to be a challenge and is being closely monitored.

Meter Reading Performance Measurement

Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the MRPM is 0.5% or less. As stated in the AVC Enbridge Gas anticipates MRPM to be in the range of 4% (or 3% if we exclude meters where access is not granted by customers). The November 2022 year to date result is 4.38% (2.66% when meters with access issues are removed). Enbridge Gas is continuing to work diligently through implementation of its mitigation plan as outlined in the AVC and aims to achieve this revised MRPM for 2022.

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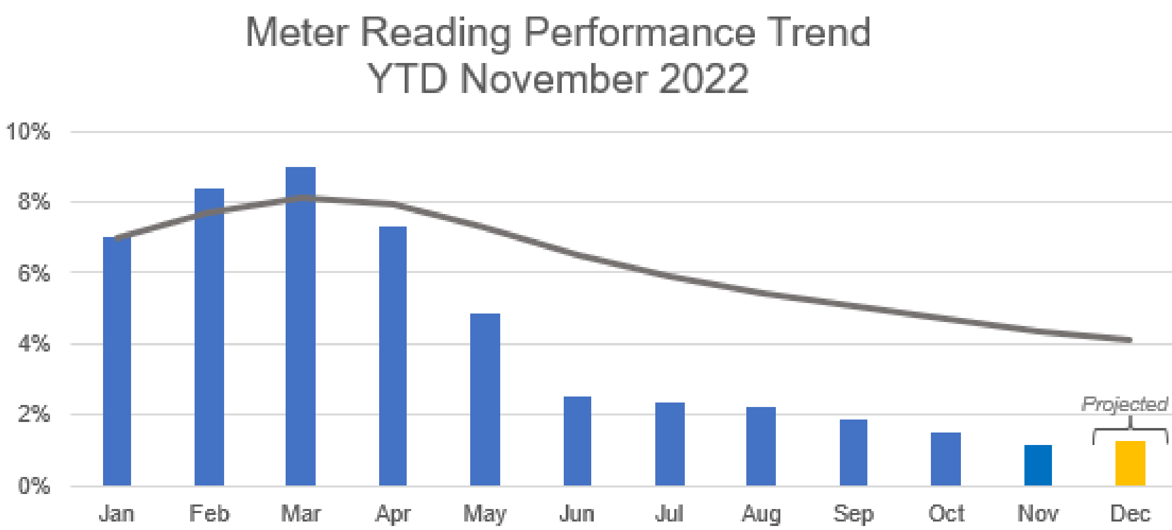


Mitigation Activities

- Continue working with internal staff and third-party vendors to assist with attaining reads to offset attrition and absenteeism impacts.
- Continue to hire resources to mitigate increased absences.
- Daily emails continue to be sent out encouraging customers to submit a reading.
- Meter readers continue to work overtime, including evenings and weekends to attain reads.
- Additional back office staff has been hired and are processing the additional reads coming in.

Challenges

- Attrition and illness/absence continue to be a challenge. Year to date attrition rates are 20% and absenteeism rates are 17%.
- Hiring challenges continue due to the tight labour market.
- Ongoing access issues: 50% of our current consecutive estimates are due to access limited by customers.

memo

Date: January 16, 2023

To: Brian Hewson, Vice President Consumer Protection & Industry Performance, OEB

From: Tracy Lynch, Director Customer Care Operations, EGI

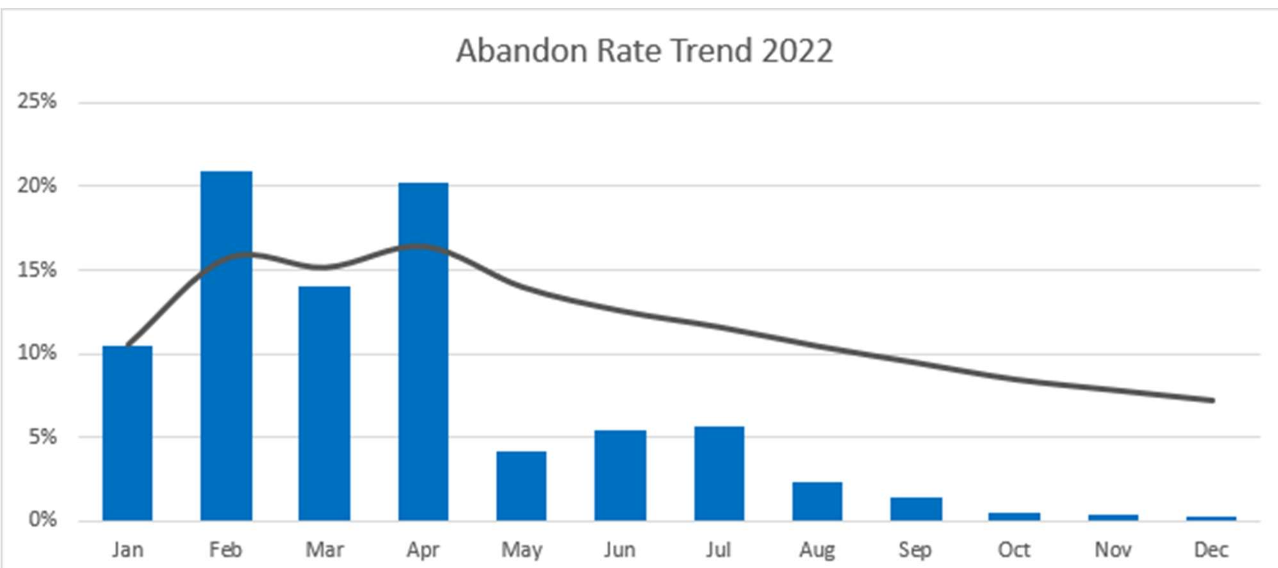
cc: Richard Lanni, Senior Legal Counsel, Legal Services, OEB
Donna Kinapen, Manager, Consumer Policy & Compliance, OEB

Re: **Service Quality Requirements (SQR): Abandon Rate, Call Answering Service Level, Meter Reading Performance Measurement**

As part of the Assurance of Voluntary Compliance (AVC) filed on September 14, 2022, Enbridge Gas committed to providing monthly reporting to OEB staff on the progress of the SQR metrics. Below is a summary of the status of each metric as of December 31, 2022.

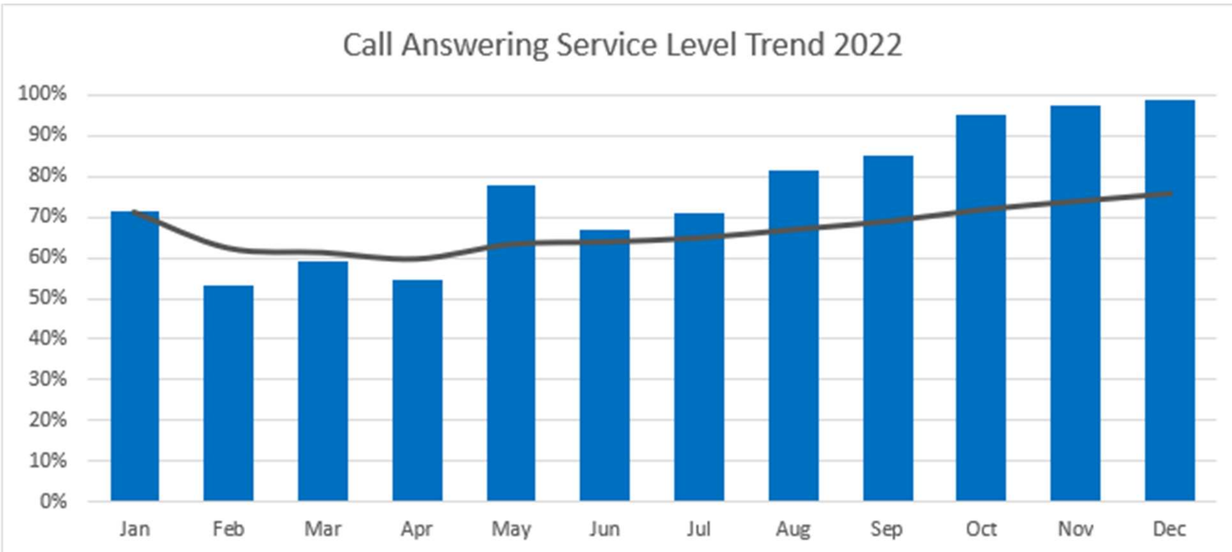
Abandon Rate

Abandon Rate (AR) tracks the percentage of callers who hang up while waiting for a live operator. The annual standard is not to exceed 10%. The December 2022 year end result is 7.1%.



Call Answering Service Level

Call Answering Service Level (CASL) tracks the percentage of calls reaching the general inquiry number, including IVR calls that are answered within 30 seconds. The yearly performance standard for CASL is 75% with a minimum monthly standard of 40%. The December 2022 year end result is 75.94%. Enbridge Gas has continued to work diligently through implementation of its mitigation plan as outlined in the AVC to achieve CASL for 2022.



Mitigation Activities

- Ongoing hiring and training of new staff to assist with high call volumes at all call centre locations.
- Proactive planning for customer communications on key information to assist with call volumes.
- Focus on employee engagement activities to promote mental wellness and retention.

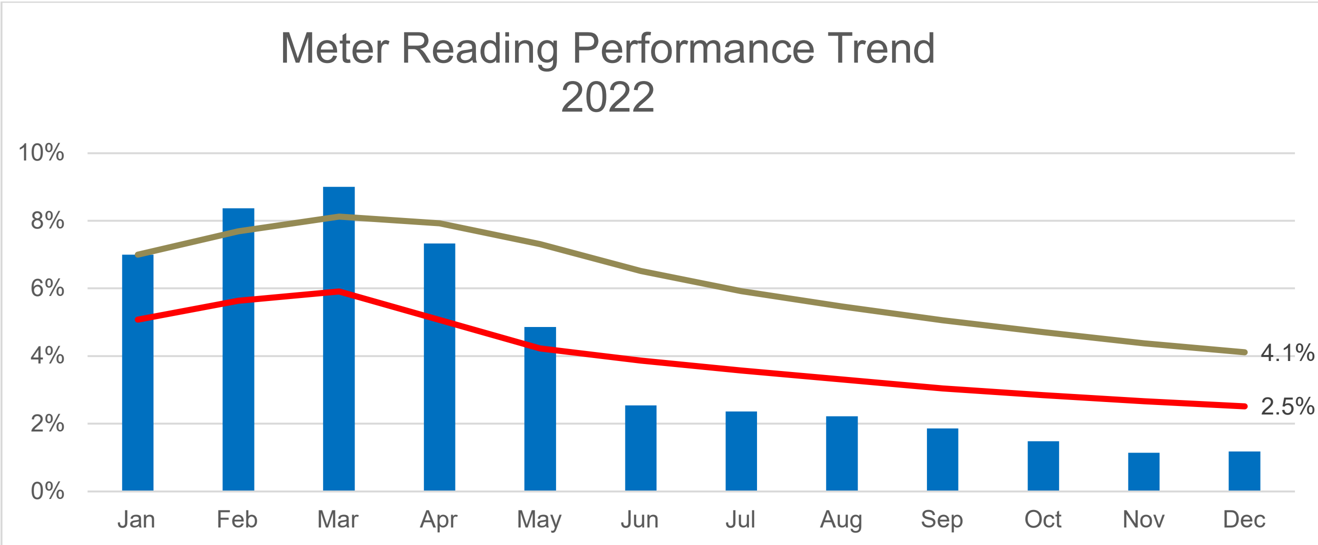
Challenges

- Call volumes continue to be higher as a result of trending call types including rate increases, payment plans, and early heating season inquiries.
- Illness and absenteeism continue to be a challenge and is being closely monitored.

Meter Reading Performance Measurement

Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the MRPM is 0.5% or less. As stated in the AVC Enbridge Gas anticipates MRPM to be in the range of 4% (or 3% if we exclude meters where access is not granted by customers). The December 2022 year end result is 4.1% (2.51% after excluding meters where access is not granted). Enbridge Gas has continued to work diligently through implementation of its mitigation plan as outlined in the AVC to achieve this revised MRPM for 2022.

ENBRIDGE



Mitigation Activities

- Continue working with internal staff and third-party vendors to assist with attaining reads to offset attrition and absenteeism impacts.
- Continue to hire resources to mitigate increased absences.
- Emails continue to be sent out encouraging customers to submit a reading.
- Meter readers continue to work overtime, including evenings and weekends to attain reads.
- Additional back office staff has been hired and are processing the additional reads coming in.

Challenges

- Attrition and illness/absence continue to be a challenge. Attrition rates are 20% and absenteeism rates are 17%.
- Hiring challenges continue due to the tight labour market.
- Ongoing access issues: 40% of our current consecutive estimates are due to access limited by customers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit 1, Tab 7, Schedule 1, Attachment 1, EGI OEB Scorecard

Preamble:

Call Answering Service is below standard.

Question(s):

Given the explanation in evidence, what specific steps has EGI taken/will take to:

i. correct the problems.
ii. achieve above standard performance in 2023/2024?

Response:

Please see response at Exhibit I.1.7-STAFF-13.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 7. Schedule 1, pg. 10-14

Preamble:

Notwithstanding EGI's Assurance Voluntary Compliance dated 20220912, we are concerned about how the meter reading and billing issue has been managed since FRPO first tried to raise this issue with EGI through interrogatories in EB-2021-0148 in late 2021.

Question(s):

For each of the four years of 2019, 2020, 2021 and 2022, separately for each rate zone, please provide the cost of:

a) Meter-reading

b) Bill production

c) Customer accounting/receivables.

Response:

a) Table 1 shows meter reading costs separated by Union and EGD rate zones.

Table 1
Meter Reading Costs

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Actual
		(a)	(b)	(c)	(d)
1	Union	6.9	7.2	7.6	8.4
2	EGD	10.4	10.0	10.9	11.8
3	Total	17.3	17.2	18.5	20.1

b) Table 2 shows bill production costs. As part of the integration, Enbridge Gas discontinued bill production services beginning in May 2020 with the Union third-party vendor and expanded services with the EGD third-party vendor to include Union customers as well. As a result, bill production costs could only be provided by rate zone for 2019 and 2020 from January 2020 to April 2020 as costs were consolidated under a single third-party vendor. For the purposes of integration related to third-party service bill production, Enbridge Gas no longer requires the vendor to differentiate services by Union and EGD, therefore the breakdown by rate zone is unavailable.

Table 2
Bill Production Costs

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Actual
		(a)	(b)	(c)	(d)
1	Union	1.5	0.7	0.0	0.0
2	EGD	3.0	1.0	0.0	0.0
3	EGI	0.0	2.2	4.0	4.1
4	Total	4.5	3.9	4.0	4.1

c) Table 3 shows customer accounting/receivables costs for cheque payment processing. All other forms of payment are electronic, and the costs are not reflected in the table because they are not part of Customer Care O&M costs.

As part of the integration, Enbridge Gas discontinued cheque payment processing services beginning in July 2021 with the Union third-party vendor and expanded services with the EGD third-party vendor to include Union customers as well. As a result, cheque payment processing costs could only be provided by rate zone for 2019 and 2021 from January to June as costs were consolidated under a single third-party vendor. For the purposes of integration related to third-party services for cheque payment processing, EGD no longer requires the vendor to differentiate services by Union and EGD, therefore the breakdown by rate zone is unavailable.

Table 3
Customer Accounting/Receivables Costs

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Actual
		(a)	(b)	(c)	(d)
1	Union	0.3	0.3	0.1	0.0
2	EGD	0.4	0.4	0.2	0.0
3	EGI	0.0	0.0	0.2	0.4
4	Total	0.6	0.7	0.5	0.4

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 7. Schedule 1, pg. 10-14

Preamble:

Notwithstanding EGI's Assurance Voluntary Compliance dated 20220912, we are concerned about how the meter reading and billing issue has been managed since FRPO first tried to raise this issue with EGI through interrogatories in EB-2021-0148 in late 2021.

Question(s):

For each of the four years of 2019, 2020, 2021 and 2022, please provide the number of bills produced by:

a) Electronic meter read (instrument on meter through phone line)

b) Manual meter read with handle held equipment

c) Estimated meter read

d) No read.

Response:

a) Total number of bills produced by electronic meter read (instrument on meter through phone line) for the years of 2019 to 2022.

Table 1

Year	Bills produced by electronic meter read Instrument
2019	37,404
2020	37,258
2021	38,047
2022	38,140

b) Total number of bills produced by manual meter read for the years of 2019 to 2022.

Table 2

Year	Bills produced by manual meter read
2019	20,438,404
2020	20,764,748
2021	18,620,824
2022	18,585,750

c) Total number of bills produced by estimated meter read for the years of 2019 to 2022.

Table 3

Year	Bills produced by estimated meter read
2019	23,905,229
2020	24,159,757
2021	25,024,976
2022	26,250,930

d) Zero consumption on a gas bill would be based on a customer's consumption behaviour, such as seasonal gas use, or in the case where the meter is temporarily locked. Total number of bills produced with no consumption for the years of 2019 to 2022.

Table 4

Year	Bills with no consumption
2019	947,167
2020	979,094
2021	1,204,570
2022	1,051,011

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 7. Schedule 1, pg. 10-14

Preamble:

Notwithstanding EGI's Assurance Voluntary Compliance dated 20220912, we are concerned about how the meter reading and billing issue has been managed since FRPO first tried to raise this issue with EGI through interrogatories in EB-2021-0148 in late 2021.

Question(s):

Please provide the monthly reports submitted to the Board as a result of this Voluntary Compliance.

Response:

Please see response at Exhibit I.1.7-STAFF-13 Attachments 1-4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 7. Schedule 1, pg. 10-14

Preamble:

Notwithstanding EGI's Assurance Voluntary Compliance dated 20220912, we are concerned about how the meter reading and billing issue has been managed since FRPO first tried to raise this issue with EGI through interrogatories in EB-2021-0148 in late 2021.

Question(s):

Please confirm that some Direct Purchase contracts have been required to balance their deliveries and consumption even though the balance was in question due to missing or estimated reads.

a) How has EGI handled those situations?

b) Will that approach be maintained going forward until ongoing billing issues have resolved?

c) If not, why not?

Response:

Contractual balancing requirements continue to exist for all direct purchase contracts. However, in situations where consumption has been identified to be significantly impacted due to missing meter readings and/or estimated or re-billed readings that do not appear to be reasonable, Enbridge Gas has taken steps to mitigate the impact to direct purchase customers.

a-c) Enbridge Gas has, and will continue to, accommodate requests to mitigate billing impacts to direct purchase customers by providing balancing flexibility when operationally available and by waiving and/or adjusting associated fees.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Ex. 1, Tab 7. Schedule 1, pg. 10-14

Preamble:

Notwithstanding EGI's Assurance Voluntary Compliance dated 20220912, we are concerned about how the meter reading and billing issue has been managed since FRPO first tried to raise this issue with EGI through interrogatories in EB-2021-0148 in late 2021.

Question(s):

Please confirm that some Direct Purchase contracts were not in a position to make balancing transactions due to uncertainty caused by missing or estimated reads.

a) If a customer transacts to balance their contract and the consumption is subsequently changed through a billing adjustment resulting in out of tolerance balances, how has EGI handled those balancing fees.

b) Will that approach be maintained going forward until ongoing billing issues have resolved? If not, why not?

Response:

a-b) Please see response at Exhibit I.1.7-FRPO-11.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit 1, Tab 7, Sch. 1, para. 29

Question(s):

What is the current status of the EGI exemption request for 2023 for the SQR measures noted in the paragraph?

Response:

On December 23, 2022, Enbridge Gas was notified by the OEB,[1] that it has decided Enbridge Gas's Application for a Partial and Temporary Exemption from Sections 7.3.1.1, 7.3.3.1 and 7.3.4.2 of the Gas Distribution Access Rule for 2023 will not be processed at this time, as this proposal to revise Enbridge Gas's SQRs is also a matter in Enbridge Gas's 2024 Rebasing proceeding.

[1] OEB Letter, EB-2022-0276, December 23, 2022. Content Manager WebDrawer - Search Results (oeb.ca)

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit 1, Tab 7, Sch. 1, para. 29

Question(s):

Did EGI do any customer engagement with respect to the modified measures that are being proposed? If yes, please provide or indicate where in the customer engagement evidence these modified measures were discussed with customers. If no, please explain why not.

Response:

Enbridge Gas did not request new customer engagement with respect to the proposed modified measures set out in the exemption request. Given that this is a partial exemption, Enbridge Gas identified the factors preventing the achievement of each individual metric as provided at Exhibit 1, Tab 7, Schedule 1, pages 6 to 14 and recommended that the OEB's Chief Executive Officer conduct a review of the GDAR pursuant to Section 44 of the *Ontario Energy Board Act* and consider appropriate amendments to CASL, MRPM and TRMA.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit 1, Tab 7, Sch. 1, para. 46

Question(s):

What are the consequences to EGI of failing to meet each of the SQR's, and in particular, what are the consequences to EGI of failing to meet the current standards for the CASL, TRMA and MRPM?

Response:

Service Quality Requirements (SQRs) were added to the Gas Distribution Access Rule (GDAR) coming into effect January 1, 2007[1] to establish performance standards and measurement of customer experience for the natural gas industry in Ontario. Enbridge Gas believes that a review of the performance standards is needed to modernize the SQRs with the current business environment and customer needs, behaviors and expectations. The Company remains committed to providing a positive customer experience.

The consequences to Enbridge Gas for failing to meet the current standards are monetary and reputational. Monetary penalties for not meeting the current standards are managed through the OEB's processes for compliance. The Company provided an Assurance of Voluntary Compliance (AVC)[2] in September 2022 for Call Answering Service Level (CASL), Abandon Rate (AR) and Meter Reading Performance Measurement (MRPM). In addition, there are reputational consequences for not meeting standards for customer responsiveness. Enbridge Gas has developed mitigation plans for CASL, MRPM and Time to Reschedule a Missed Appointment (TRMA). Please see response at Exhibit I.1.7-STAFF-13.

[1] EB-2005-0453, OEB Amendments to the Gas Distribution Access Rule, March 27, 2006, pp. 1-2.
[2] EB-2022-0188, Assurance of Voluntary Compliance, Enbridge Gas Inc., September 12, 2022. EGI-Assurance-of-Voluntary-Compliance-20220912.pdf (oeb.ca)

Enbridge Gas is committed to excellent customer service, however, the safety of employees, customers, and the communities in which we operate continues to be a top priority and core value. As provided at Exhibit 1, Tab 7, Schedule 1, pages 5 to 6, at the height of the COVID-19 pandemic there were periods of time when meter readers were unable to complete routes due to public health stay-at-home orders. COVID-19 also impacted staffing, with increased illness and quarantine/isolation periods. Extreme weather events impact the ability to safely obtain meter reads. Finally, responding to emergencies is a top priority and from time-to-time field and dispatch staff are redirected from customer appointments to attend emergencies, resulting in appointments not always being rescheduled according to the prescribed timelines.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit 1, Tab 7, Sch. 1, Attachment 1

Question(s):

Please update Attachment 1 to included actual figures for 2022.

Response:

Please see response at Exhibit I.1.7-VECC-9, Attachment 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit 1, Tab 7, Schedule 1

Question(s):

a) Please provide the OEB Scorecard in the format of Attachment 1 but for the years 2013-2016 (EGD and Union).

b) Please update the Scorecard at Attachment 1 to include 2022 results

c) A review of the measures EGI is seeking relief from meeting and the historical data prior to amalgamation suggest that the two prior Utilities were able to meet all the performance measures with the exception of Time to Reschedule Missed Appointments – where both utilities were within .03% of meeting the target. Since amalgamation there has been a notable decline in a number of performance metrics – for example emergency call response has fallen from around 97-99% to 95.2% after amalgamation. Please outline the changes were made to the call centre operations subsequent to amalgamation.

d) Please provide (separately) the number of telephone calls, email and other contacts (social media etc.) for each year 2013 through 2022.

e) Does EGI outsource call center activity? If so please provide the performance measurements required by that contract.

Response:

a-b) Enbridge Gas's OEB scorecard has been updated to include EGD and Union results for 2013 through 2016, and 2022 preliminary results for Enbridge Gas. Please see Attachment 1. Financial metrics are not yet available for 2022, as these metrics are part of the annual filing for the Natural Gas Reporting and Record Keeping (RRR) Rule for Gas Utilities, due to the OEB on April 30, and require dedicated time in the first quarter of the year to be prepared and validated. The Cost per Customer and Cost per Total Kilometer of Distribution Pipe metrics are not available for 2013 through 2016. These metrics were established as part of the MAADs decision and were not historically tracked by EGD or Union.

c) Enbridge Gas began a significant effort to align systems and processes following amalgamation which affected metric performance. At the same time factors including the COVID-19 pandemic, staffing issues and extreme weather events further impacted results. Details of the impacts are provided in evidence at Exhibit 1, Tab 7, Schedule 1, pages 4 to 12, and 15 to 17.

The integration of systems and processes resulted in a positive change to customer call centre operations for Enbridge Gas. With aligned systems and processes and cross-trained staff across multiple call centre locations, customer call centres can provide seamless backup for increased call volumes, staffing shortages and system outage management. Existing internal call centre operations for Emergency Call Handling and the Customer Contact Centre did not experience changes to location or staffing as a result of amalgamation. Prior to amalgamation Enbridge Gas Distribution emergency calls were handled by an external contractor. In early 2020 Emergency Call Handling operations were harmonized, with all emergency calls now being handled internally with the addition of emergency call handling to the Toronto dispatch centre.

There were significant changes for the organization with system integration and subsequent process alignment, temporarily impacting productivity. In addition, some metrics were impacted by similar alignment activities and reporting practice adjustments. For example, emergency call handling process alignment resulted in an increased number of calls being classified as an emergency, which marginally impacted response volumes in the field and ultimately the Emergency Response SQR results.

d) The number of calls Enbridge Gas (EGD and Union prior to amalgamation) received from 2012 to 2022 is provided in Table 1.

Table 1

Year	Number of Calls	
	EGD	Union
2013	2,615,084	1,157,206
2014	2,747,715	1,285,561
2015	2,862,347	1,193,792
2016	2,654,978	1,110,893
2017	2,378,139	1,151,592
2018	2,478,162	1,082,381
	EGI	
2019	3,588,323	
2020	3,001,431	
2021	3,609,331	
2022	3,615,137*	

*preliminary result

In addition, in 2022 customers completed nearly 1.9 million transactions through the Enbridge Gas website and chat. Enbridge Gas does not track email and social media volumes as they are not primary channels for customer contact.

e) Enbridge Gas outsources a portion of its Customer Contact Centre. The vendor is required to meet service levels for call management. The results are included within the scorecard for the Abandonment Rate (AR) and the Call Answering Service Level (CASL). The vendor is required to meet an AR of less than 10% per calendar year. The vendor is also required to achieve 50% of calls answered within 30 seconds each month and 55% per calendar year. This service level is not inclusive of the Interactive Voice Response (IVR) calls which is another component of the CASL metric results.

EGI OEB SCORECARD 2013 - 2022

#	Performance Measure	Target	Actual 2022[1] EGI	Actual 2021 EGI	Actual 2020 EGI	Actual 2019 EGI	Actual 2018 LEGD	2018 LUG	Actual 2017 LEGD	2017 LUG	Actual 2016 LEGD	2016 LUG	Actual 2015 LEGD	2015 LUG	Actual 2014 LEGD	2014 LUG	Actual 2013 LEGD	2013 LUG
#	**CUSTOMER FOCUS (Service Quality & Customer Satisfaction)**																	
1	**Reconnection Response Time (# of days to reconnect a customer)** (# of reconnections completed within 2 business days/# of reconnections completed)	85.0%	98.1%	96.9%	98.9%	98.1%	97.3%	90.7%	96.2%	90.5%	93.8%	86.2%	94.6%	90.1%	94.0%	91.9%	92.6%	92.2%
2	**Scheduled appointments met on time (appointments met within designated time period)** (# of appointments met within 4hrs of the scheduled date/# of appointments scheduled in the month)	85.0%	95.4%	94.5%	98.8%	98.5%	94.7%	98.8%	94.3%	99.0%	94.8%	98.9%	95.2%	98.8%	95.1%	97.7%	94.2%	97.8%
3	**Telephone calls answered on time (call answering service level)** (# of calls answered within 30 seconds / # of calls received)	75.0%	75.9%	64.3%	75.2%	79.0%	82.0%	77.6%	82.5%	79.2%	82.4%	80.1%	79.7%	79.1%	79.0%	73.6%	75.9%	78.4%
4	**Customer Complaint Written Response (# of days to provide a written response)** # of complaints requiring response within 10 days / # of complaints requiring a written response	80.0%	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	95.5%	100.0%	100.0%	100.0%	93.3%	100.0%	94.5%	100.0%
5	**Billing accuracy** 'The requirement states that utilities should complete manual checks of their bills to verify data when a meter read demonstrates excessively high or low usage.'		390,246 manual checks completed as per QAP	384,858 manual checks completed as per QAP	427,524 manual checks completed as per QAP	429,386 manual checks completed as per QAP	224,316 manual checks completed as per QAP	218,700 manual checks completed as per QAP	494,330 manual checks completed as per QAP	167,075 manual checks completed as per QAP	453,326 manual checks completed as per QAP	171,381 manual checks completed as per QAP	478,248 manual checks completed as per QAP	173,132 manual checks completed as per QAP	462,936 manual checks completed as per QAP	154,888 manual checks completed as per QAP	524,103 manual checks completed as per QAP	140,497 manual checks completed as per QAP
6	**Abandon Rate (# of calls abandon rate)** (# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent)	10.0%	7.1%	16.0%	5.4%	2.50%	1.9%	2.6%	1.8%	3.4%	1.8%	3.6%	2.4%	4.0%	1.9%	4.7%	2.8%	3.8%
7	**Time to Reschedule Missed Appointments** (% of rescheduled work within 2 hours of the end of the original appointment time)	100.0%	93.8%	97.0%	97.3%	97.0%	98.7%	99.8%	96.8%	99.9%	94.2%	99.8%	94.8%	99.8%	95.5%	99.9%	95.0%	99.9%
	OPERATIONAL EFFECTIVENESS (Safety, System Reliability, Asset Management & Cost Control)																	
8	**Meter Reading Performance** # of meters with no read for 4 consecutive months / # of active meters to be read	0.5%	4.1%	5.0%	4.4%	0.7%	0.5%	0.4%	0.5%	0.1%	0.4%	0.1%	0.5%	0.2%	0.7%	0.4%	0.5%	0.2%
9	**% of Emergency Calls Responded within One Hour** (# of emergency calls responded within 60 minutes / # of emergency calls)	90.0%	94.1%	95.2%	96.7%	96.7%	96.6%	99.3%	96.8%	99.0%	96.1%	98.8%	96.7%	98.6%	96.9%	97.8%	96.1%	97.9%
10	**Compression Reliability** % reliable for transmission compression		100.0%	99.7%	99.7%	99.9%	NA	99.8%	NA	99.9%	NA	99.7%	NA	99.8%	NA	99.9%	NA	99.8%
11	**Damages per 1000 locate requests**		2.31	1.95	2.22	1.97	1.85	2.28	1.83	2.17	2.19	2.41	2.46	2.56	2.49	2.67	2.84	3.06
12	**Total Cost per Customer** ($ / Customer)		N/A[2]	643.94	658.2	653.6	530.7	756.7	513.9	730.3	N/A[5]	N/A[5]	N/A[5]	N/A[5]	N/A[5]	N/A[5]	N/A[5]	N/A[5]
13	**Total Cost per km of Distribution Pipe** ($ / km of Distribution Pipe)		N/A[2]	16,639.6	16,928.5	16,735.4	15,123.1	16,947.5	14,739.7	16,109.4	N/A[5]	N/A[5]	N/A[5]	N/A[5]	N/A[5]	N/A[5]	N/A[5]	N/A[5]
	PUBLIC POLICY RESPONSIVENESS (Conservation & Demand Management & Connection of Renewable Generation)																	
14	**Total Cumulative Cubic Meters of Natural Gas Saved (Net)** (Millions)		N/A[3]	1,707.5[4]	1,632.2	2,075.9	807.5	1,124.5	787.2	1,182.7	837.1	959.4	826.2	1,750.8	719.8	1,889.5	826.9	2,820.8
	FINANCIAL PERFORMANCE (Financial Ratios)																	
15	**Current Ratio** (Current Assets / Current Liabilities)		N/A[2]	0.71	0.66	0.75	0.93	0.69	0.84	0.47	0.7	0.64	0.87	0.77	0.65	0.81	0.74	0.77
16	**Debt Ratio** (Total Debt / Total Assets)		N/A[2]	0.41	0.40	0.40	0.49	0.51	0.47	0.49	0.47	0.47	0.47	0.48	0.49	0.45	0.46	0.46
17	**Debt to Equity Ratio** (Total Debt / Shareholders' Equity)		N/A[2]	1.06	1.01	0.98	1.67	2.12	1.54	2.08	1.48	2.06	1.59	2.08	1.69	2.12	1.61	2.05
18	**Interest Coverage** (EBIT / Interest Charges)		N/A[2]	2.55	2.34	2.53	2.52	2.69	1.96	2.42	2.07	2.33	2.18	2.33	2.3	2.46	2.61	2.47
19	**Financial Statement Return on Assets** (Net Income / Total Assets)		N/A[2]	2.07%	1.97%	2.25%	2.98%	3.20%	2.27%	2.71%	2.26%	2.58%	2.38%	2.70%	2.60%	2.87%	3.06%	3.35%
20	**Financial Statement Return on Equity** (Net Income / Shareholders' Equity)		N/A[2]	5.32%	4.96%	5.56%	10.20%	13.25%	7.39%	11.43%	7.17%	11.39%	8.00%	11.71%	8.99%	13.43%	10.61%	14.85%

[1] 2022 results, where provided are prelimary
[2] 2022 results will be available April 30, 2023
[3] 2022 results will be available in 2024
[4] 2021 results are audited and to be approved in the DSM Clearance Proceeding
[5] 2013 through 2016 results are not available as the metrics were not historically tracked by EGD or Union

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 8, Schedule 1, Attachment 1
Exhibit 1, Tab 8, Schedule 1, Attachment 2
Exhibit 1, Tab 8, Schedule 1, Attachment 9
Exhibit 1, Tab 8, Schedule 1, Attachment 11
Exhibit 1, Tab 8, Schedule 1, Attachment 12

Question(s):

Enbridge Gas has provided the following:

- Consolidated financial statements for 2020 and 2021.
- Pro-forma statement of utility income for 2023 bridge year.
- Rating reports from DBRS Morningstar (September 27, 2022) and S&P Global Ratings (February 1, 2022).

a) As Concentric has compared Enbridge Gas's risk profile in 2022 to Enbridge Gas Distribution (EGD) and Union Gas Limited's (Union Gas) risk profile in 2012, please provide the following information starting from 2012 (all information to be provided for Enbridge Gas):

   i. Audited financial statements for 2019, including income statement, balance sheet and cash flow statement in MS Excel format.
   ii. Audited financial statements, if available, or draft financial statements for 2022, including income statement, balance sheet and cash flow statement in MS Excel format.
   iii. Pro-forma financial statements, prepared in the same manner as Enbridge Gas's audited financial statements, for 2023, 2024, 2025, 2026, 2027 and 2028 (including income statement, balance sheet and cash flow statement in MS Excel format).
   iv. All relevant credit rating reports from DBRS Morningstar and S&P Global Ratings from 2019 to 2022.

b) As Concentric has compared Enbridge Gas's risk profile in 2022 to EGD and Union Gas's risk profile in 2012, please provide the following information starting from 2012 (all information to be provided separately for EGD and Union Gas):

i. Audited financial statements for 2012, 2013, 2014, 2015, 2016, 2017 and 2018 (including income statement, balance sheet and cash flow statement in MS Excel format).
ii. All relevant credit rating reports from DBRS Morningstar and S&P Global Ratings from 2012 to 2018.

Response:

a)

i. Please see Attachment 1 for the PDF versions of the 2018 and 2019 Audited Financial Statements and Attachment 2 for the Excel versions. Please note that Enbridge Gas filed a combined set of Audited Financial Statements for 2018 and no standalone Financial Statements were filed in 2018 for EGD or Union.

ii. Please see Attachment 3 for the PDF version of the 2022 Audited Financial Statements and Attachment 4 for the Excel versions.

iii. As Enbridge Gas is setting cost of service rates for 2024 based on 2024 forecast information, Enbridge Gas declines to provide the requested forecast information beyond 2024. Any forecast of post-2024 will depend on the determinations in this proceeding. Please see Exhibit 1, Tab 8, Schedule 1, Attachment 9 for Enbridge Gas's pro-forma financial information. Enbridge Gas does not produce pro-forma financial statements in the same manner as the audited financial statements.

iv. Please see Attachment 5 and Attachment 6 for credit rating agency reports from DBRS Morningstar and S&P Global Ratings from 2019 to 2022.

b)

i. Please see Attachments 7 and 8 for the PDF versions of the 2012 through 2017 Audited Financial Statements for EGD and Union and Attachments 9 and 10 for the Excel versions.

ii. Please see Attachments 11 through 14 for credit rating agency reports from DBRS Morningstar and S&P Global Ratings from 2012 to 2018. Note that S&P Global did not publish reports for EGD or Union Gas in 2018.

ENBRIDGE GAS INC.
(a subsidiary of Enbridge Inc.)

COMBINED FINANCIAL STATEMENTS

December 31, 2018

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Gas Inc.

Financial Reporting
Management of Enbridge Gas Inc. (the Company) is responsible for the accompanying Combined Financial Statements. The Combined Financial Statements have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors is responsible for all aspects related to governance of the Company. The Company does not have an Audit Committee, having received an exemption from such requirement.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare Combined Financial Statements for external reporting purposes in accordance with U.S. GAAP and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, have conducted an audit of the Combined Financial Statements of the Company in accordance with Canadian generally accepted auditing standards and have issued an unqualified audit report, which is accompanying the Combined Financial Statements.

(Signed)

Cynthia L. Hansen
President

(Signed)

Wendy Zelond
Vice President, Finance

February 15, 2019

Independent auditor's report

To the Shareholders of Enbridge Gas Inc.

Our opinion

In our opinion, the accompanying combined financial statements present fairly, in all material respects, the financial position of Enbridge Gas Inc. (the Company) as at December 31, 2018 and 2017, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America (US GAAP).

What we have audited
The Company's combined financial statements comprise:

- the combined statements of earnings for the years ended December 31, 2018 and 2017;
- the combined statements of comprehensive income for the years ended December 31, 2018 and 2017;
- the combined statements of shareholders' equity for the years ended December 31, 2018 and 2017;
- the combined statements of cash flows for the years ended December 31, 2018 and 2017;
- the combined statements of financial position as at December 31, 2018 and 2017; and
- the notes to the combined financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the combined financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the combined financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

Emphasis of matter - Combined financial statements

We draw attention to the fact that, as described in note 1 to the combined financial statements, the businesses included in the combined financial statements have not operated as a single entity. These combined financial statements are, therefore, not necessarily indicative of results that would have occurred if the businesses had operated as a single business during the years presented or of future results of the combined businesses. Our opinion is not modified in respect of this matter.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the combined financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the combined financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the combined financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the combined financial statements

Management is responsible for the preparation and fair presentation of the combined financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of combined financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the combined financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the combined financial statements

Our objectives are to obtain reasonable assurance about whether the combined financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these combined financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the combined financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the combined financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the combined financial statements, including the disclosures, and whether the combined financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the combined financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Ontario
February 15, 2019

ENBRIDGE GAS INC.
COMBINED STATEMENTS OF EARNINGS

Year ended December 31,	**2018**	2017
(millions of Canadian dollars)		
Operating Revenues *(Notes 4 and 20)*		
Gas commodity and distribution revenue	**4,230**	3,830
Storage and transportation revenue	**984**	993
Other revenue	**83**	76
Total operating revenues	**5,297**	4,899
Operating Expenses		
Gas commodity and distribution costs *(Note 20)*	**2,676**	2,699
Operating and administrative *(Note 20)*	**1,077**	951
Depreciation and amortization *(Notes 8 and 9)*	**608**	554
Earnings sharing *(Note 4)*	**—**	24
Total operating expenses	**4,361**	4,228
Operating Income	**936**	671
Other income *(Note 20)*	**80**	75
Interest expense, net *(Notes 12, 15 and 20)*	**(391)**	(356)
Earnings before income taxes	**625**	390
Income tax (expense)/recovery *(Note 16)*	**(57)**	17
Earnings	**568**	407
Preference share dividends *(Note 13)*	**(6)**	(5)
Earnings attributable to the common shareholders	**562**	402

The accompanying notes are an integral part of these combined financial statements.

ENBRIDGE GAS INC.
COMBINED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2018**	2017
(millions of Canadian dollars)		
Earnings	**568**	407
Other comprehensive income/(loss), net of tax *(Notes 14 and 15)*		
Change in unrealized loss on cash flow hedges	**(4)**	—
Reclassification to earnings of realized loss on cash flow hedges	**3**	3
Actuarial loss on pension plans and other postretirement benefits (OPEB) *(Note 17)*	**(15)**	(24)
Foreign currency translation adjustment	**4**	(3)
Other comprehensive loss, net of tax	**(12)**	(24)
Comprehensive income	**556**	383
Preference share dividends	**(6)**	(5)
Comprehensive income attributable to the common shareholders	**550**	378

The accompanying notes are an integral part of these combined financial statements.

ENBRIDGE GAS INC.
COMBINED STATEMENTS OF SHAREHOLDERS' EQUITY

	Preference shares *(Note 13)*	Common shares *(Note 13)*	Additional paid-in capital	Retained earnings/ (deficit)	Accumulated other comprehensive loss *(Note 14)*	Total
(millions of Canadian dollars)						
December 31, 2016	100	1,917	1,148	62	(15)	3,212
Balances transferred from Union Gas *(Note 1)*	110	657	6,105	—	—	6,872
Earnings attributable to the common shareholders	—	—	—	402	—	402
Other comprehensive loss, net of tax	—	—	—	—	(24)	(24)
Common shares issued *(Note 20)*	—	500	—	—	—	500
Common shares dividends declared *(Note 20)*	—	—	—	(600)	—	(600)
December 31, 2017	210	3,074	7,253	(136)	(39)	10,362
Preference shares redeemed	**(210)**	**—**	**—**	**—**	**—**	**(210)**
Earnings attributable to the common shareholders	**—**	**—**	**—**	**562**	**—**	**562**
Other comprehensive loss, net of tax	**—**	**—**	**—**	**—**	**(12)**	**(12)**
Common shares issued *(Note 20)*	**—**	**407**	**—**	**—**	**—**	**407**
Return of capital *(Note 20)*	**—**	**(451)**	**—**	**—**	**—**	**(451)**
Common shares dividends declared *(Note 20)*	**—**	**—**	**—**	**(765)**	**—**	**(765)**
December 31, 2018	**—**	**3,030**	**7,253**	**(339)**	**(51)**	**9,893**

The accompanying notes are an integral part of these combined financial statements.

ENBRIDGE GAS INC.
COMBINED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2018**	2017
(millions of Canadian dollars)		
Operating activities		
Earnings	**568**	407
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization *(Notes 8 and 9)*	**608**	554
Deferred income tax expense *(Note 16)*	**(31)**	(44)
Net defined pension and other postretirement benefit obligations (OPEB) costs *(Note 17)*	**(26)**	(44)
Other	**6**	7
Changes in operating assets and liabilities *(Note 18)*	**601**	253
Net cash provided by operating activities	**1,726**	1,133
Investing activities		
Proceeds from wind down of investment in affiliate *(Notes 15 and 20)*	**825**	—
Capital expenditures	**(881)**	(1,071)
Additions to intangible assets	**(412)**	(692)
Change in construction payable	**(34)**	(5)
Net cash used in investing activities	**(502)**	(1,768)
Financing activities		
Net change in short-term borrowings *(Note 12)*	**(420)**	777
Net change in short-term borrowings from affiliates *(Notes 12 and 20)*	**—**	(154)
Long-term borrowings from affiliates *(Notes 12 and 20)*	**575**	—
Term note issuances, net of issue costs *(Note 12)*	**—**	795
Term note repayments *(Note 12)*	**(400)**	(625)
Common shares issued *(Notes 13 and 20)*	**407**	500
Common share dividends *(Note 20)*	**(765)**	(659)
Preference shares redeemed *(Note 13)*	**(210)**	—
Preference share dividends	**(7)**	(5)
Return of capital *(Notes 13 and 20)*	**(451)**	—
Net cash provided by/(used in) financing activities	**(1,271)**	629
Net increase/(decrease) in cash, cash equivalents and restricted cash	**(47)**	(6)
Cash, cash equivalents and restricted cash at beginning of year	**96**	62
Cash, cash equivalents and restricted cash transferred from Union Gas *(Note 1)*	**—**	40
Cash, cash equivalents and restricted cash at end of year	**49**	96
Supplementary cash flow information		
Cash paid/(received) for income taxes	**(33)**	38
Cash paid for interest, net of amounts capitalized	**386**	342
Property, plant and equipment non-cash accruals	**65**	58

The accompanying notes are an integral part of these combined financial statements.

ENBRIDGE GAS INC.
COMBINED STATEMENTS OF FINANCIAL POSITION

December 31,	**2018**	2017
(millions of Canadian dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**17**	39
Restricted cash	**32**	57
Accounts receivable and other *(Notes 6, 7 and 16)*	**1,312**	1,643
Accounts receivable from affiliates *(Note 20)*	**22**	47
Gas inventory *(Note 6)*	**687**	633
Assets held for sale, current *(Note 5)*	**22**	15
	2,092	2,434
Property, plant and equipment, net *(Note 8)*	**14,818**	14,344
Investment in affiliate *(Notes 15 and 20)*	**—**	825
Deferred amounts and other assets *(Notes 6, 10, 16 and 17)*	**1,931**	1,862
Intangible assets, net *(Note 9)*	**209**	855
Goodwill *(Note 1)*	**4,784**	4,784
Assets held for sale, long-term *(Note 5)*	**116**	110
Total assets	**23,950**	25,214
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings *(Note 12)*	**1,025**	1,445
Accounts payable and other *(Notes 6, 11, 15, 16 and 17)*	**1,315**	1,386
Accounts payable to affiliates *(Note 20)*	**55**	82
Current portion of long-term debt *(Note 12)*	**—**	412
Liabilities held for sale, current *(Note 5)*	**44**	43
	2,439	3,368
Long-term debt *(Note 12)*	**7,543**	7,567
Other long-term liabilities *(Notes 6, 15 and 19)*	**1,773**	2,292
Deferred income taxes *(Note 16)*	**1,319**	1,216
Loans from affiliate *(Notes 12 and 20)*	**950**	375
Liabilities held for sale, long-term *(Note 5)*	**33**	34
	14,057	14,852
Shareholders' equity		
Share capital *(Note 13)*		
Preference shares *(convertible; nil and 8 outstanding at December 31, 2018 and 2017, respectively)*	**—**	210
Common shares *(291 and 271 outstanding at December 31, 2018 and 2017, respectively)*	**3,030**	3,074
Additional paid-in capital	**7,253**	7,253
Retained earnings	**(339)**	(136)
Accumulated other comprehensive loss *(Note 14 and 17)*	**(51)**	(39)
	9,893	10,362
Total liabilities and shareholders' equity	**23,950**	25,214

The accompanying notes are an integral part of these combined financial statements.

Approved by the Board of Directors:

(Signed)

Cynthia L. Hansen
Director

(Signed)

David G. Unruh
Director

NOTES TO THE COMBINED FINANCIAL STATEMENTS

1. BUSINESS OVERVIEW

Enbridge Gas Inc. (Enbridge Gas) is a rate-regulated natural gas distribution, storage and transmission utility, serving residential, commercial and industrial customers in Ontario. Enbridge Gas also serves areas in northern New York State through its wholly-owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence Gas), an asset held for sale *(Note 5)*.

AMALGAMATION AND COMBINED FINANCIAL STATEMENTS

On August 30, 2018, Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas) received approval by the Ontario Energy Board (OEB) for their application to amalgamate on January 1, 2019, as described in *Note 6 Regulatory Matters.* The amalgamated company has continued from this date as Enbridge Gas. Enbridge Gas continues to have all of the assets, rights, contracts, liabilities and obligations of each of EGD and Union Gas, including licenses and permits.

Prior to the amalgamation, EGD and Union Gas were both indirect wholly-owned subsidiaries of Enbridge Inc. (Enbridge) and operated as companies under common control since February 27, 2017, when Enbridge completed a stock-for-stock merger transaction to acquire all outstanding common stock of Spectra Energy Corp (Spectra Energy). As a result of the February 27, 2017 merger, Enbridge and its subsidiaries obtained ownership of Union Gas through its ownership in Spectra Energy.

These Combined Financial Statements have been prepared to include the results and accounts of EGD from January 1, 2017 and Union Gas from February 27, 2017, the date upon which Enbridge acquired common control of both entities. As a result, the comparability of the individual line items in the Combined Statements of Earnings, Combined Statements of Comprehensive Income and Combined Statements of Cash Flows are impacted.

In accordance with generally accepted accounting principles in the United States of America (U.S. GAAP), the Combined Financial Statements reflect EGD as the receiving entity with Union Gas' accounts transferred at Enbridge's historical cost as at February 27, 2017. The carrying values of certain assets and liabilities of Union Gas were adjusted to reflect EGD's accounting policies retrospectively to the transfer date. All intercompany transactions and balances have been eliminated.

The following table summarizes the carrying value of the assets and liabilities of Union Gas that were transferred to EGD:

February 27,	2017
(millions of Canadian dollars)	
Current assets	882
Property, plant and equipment, net	6,365
Deferred amounts and other assets	1,277
Intangible assets, net	84
Current liabilities	(1,214)
Long-term debt	(3,763)
Other long-term liabilities	(947)
Deferred income taxes	(596)
	2,088
Goodwill	4,784
	6,872

All references to "the Company" relate to the continuing, amalgamated company Enbridge Gas and the combined financial position, results of operations and cash flows for EGD and Union Gas. References to “EGD” or “Union Gas” relate to the separate legal entities as they existed prior to January 1, 2019.

2. SIGNIFICANT ACCOUNTING POLICIES

These Combined Financial Statements are prepared in accordance with U.S. GAAP. Amounts are stated in Canadian dollars unless otherwise noted.

In May 2018, Canadian securities regulators approved the extension of EGD and Union Gas' exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earliest of January 1, 2024, the first day of the Company's financial year that commences if and after the Company ceases to have activities subject to rate regulation, or the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. The Company will continue to rely upon the exemptive relief following the amalgamation of EGD and Union Gas.

BASIS OF PRESENTATION AND USE OF ESTIMATES
These Combined Financial Statements include the accounts of EGD, St. Lawrence Gas and Union Gas. All intercompany accounts and transactions are eliminated on combination.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the Combined Financial Statements. Significant estimates and assumptions used in the preparation of the Combined Financial Statements include, but are not limited to: carrying values of regulatory assets and liabilities; unbilled revenues; estimates of revenue; depreciation rates and carrying value of property, plant and equipment; amortization rates and carrying value of intangible assets; measurement of goodwill; fair value of asset retirement obligations (ARO); fair value of financial instruments; provisions for income taxes; assumptions used to measure retirement and OPEB; and commitments and contingencies. Actual results could differ from these estimates.

REGULATION
The utility operations of the Company within Ontario are regulated by the OEB, while the utility operations of St. Lawrence Gas are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities *(Note 6)*.

As a result of rate regulation accounting, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates and amounts collected from customers in advance of costs being incurred. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation accounting, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. The Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

REVENUE RECOGNITION

Revenues from contracts with customers are generally recognized upon the fulfillment of the performance obligations for the distribution, storage, transportation and sale of natural gas. For distribution and transportation service arrangements where the services are simultaneously received and consumed by the customer, revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise areas. Revenue from storage services are recognized as the storage services are provided.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue under such circumstances is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulator, which follow the accounting guidance found in *ASC 980 - Regulated Operations*.

PUSH-DOWN ACCOUNTING

EGD also elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted U.S. GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by EGD. Upon adopting push-down accounting, the historical cost of EGD's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

The Company has applied push-down accounting with respect to the accounts of Union Gas from February 27, 2017, the date upon which Enbridge acquired common control of EGD and Union Gas. The carrying values of certain assets and liabilities of Union Gas transferred to EGD have been adjusted to reflect Enbridge's historical cost as at February 27, 2017.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in interest rates and foreign exchange rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges.

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in currency exchange rates related to unregulated storage revenue and changes in interest rates *(Note 15)*. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/ loss (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

The Company recognizes the fair value of derivative instruments on the Combined Statements of Financial Position as current and non-current assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments in qualifying hedging relationships are classified as Operating activities on the Combined Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Combined Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and accounts for these costs as a deduction from Long-term debt on the Combined Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

INCOME TAXES

Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For the Company's regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent taxes can be recovered through rates *(Note 6)*. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Combined Statement of Financial Position. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Combined Statements of Earnings in the period that they arise.

The functional currency of the Company's only foreign operation, St. Lawrence Gas, is the United States dollar (USD). The effects of translating the financial statements of St. Lawrence Gas to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI). Asset and liability accounts are translated at the exchange rates in effect on the date of the Combined Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased. The Company combines Cash and cash equivalents and Bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements.

RESTRICTED CASH

Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific agreements, are presented as Restricted cash on the Combined Statements of Financial Position. Restricted cash represents funds received from the Green Investment Fund (GIF) program. The Company's use of the funds is limited to eligible expenditures for the purpose of executing the program. The Company manages the GIF program separately from its core regulated activities. There is no earnings impact related to the GIF program.

GAS INVENTORY

Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction as authorized by the Regulators. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the Regulators. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation until the last asset in the pool is disposed of. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily include: costs which the Regulators have permitted, or are expected to permit, to be recovered through future rates; deferred income taxes; and derivative financial instruments.

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs and emission allowances. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are generally amortized on a straight line basis over their expected lives, commencing when an asset is available for use.

From January 1, 2017 through July 3, 2018, emission allowances were purchased in order to meet greenhouse gas (GHG) compliance obligations and were recorded at their original cost. Refer to *Note 9 Intangible Assets* for more information.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. For the purposes of impairment testing, the Company has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. If the quantitative goodwill impairment test is performed, the Company determines the fair value of goodwill and compares those values to the carrying value. If the carrying value exceeds its fair value, goodwill impairment is measured at the amount by which the carrying value exceeds its fair value.

ASSET RETIREMENT OBLIGATIONS (AROs)

AROs associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset’s useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets, it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management’s best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality.

The Company uses mortality tables issued by the Canadian Institute of Actuaries to measure its benefit obligations of its pension plan. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Interest cost of pension plan obligations;
- Expected return on pension plan assets;
- Amortization of the prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities on the Combined Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

The Company records regulatory adjustments to reflect the difference between certain pension and OPEB costs for accounting purposes and the pension and OPEB costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension expense or OPEB costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or a liability has been incurred, and the amount of the impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW ACCOUNTING STANDARDS

Improving the Presentation of Net Periodic Benefit Cost related to Defined Benefit Plans

Effective January 1, 2018, the Company adopted ASU 2017-07 which was issued primarily to improve the income statement presentation of the components of net periodic pension cost and net periodic postretirement benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. The Company's Combined Statements of Earnings is adjusted to present the current service cost within Operating and administrative expenses and the other components of net benefit cost within Other income/(expense). For the year ended December 31, 2017, $30 million relating to the other components of net benefit cost were reclassified from Operating and administrative expenses to Other income/(expense).

Clarifying Guidance on the Application of Modification Accounting on Stock Compensation

Effective January 1, 2018, the Company adopted ASU 2017-09 and applied the standard on a prospective basis. The new standard was issued to clarify the scope of modification accounting. Under the new guidance, modification accounting is required for all changes to share based payment awards, unless all of the following are met: 1) there is no change to the fair value of the award, 2) the vesting conditions have not changed, and 3) the classification of the award as an equity instrument or a debt instrument has not changed. The adoption of this accounting update did not have a material impact on the Company's Combined Financial Statements.

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows

Effective January 1, 2018, the Company adopted ASU 2016-18 on a retrospective basis. The new standard clarifies guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the statement of cash flows. The amendments require that changes in restricted cash and restricted cash equivalents be included within cash and cash equivalents when reconciling the opening and closing period amounts shown on the statement of cash flows. For current and comparative periods, the Company amended the presentation in the Combined Statements of Cash Flows to include restricted cash with cash and cash equivalents. Net cash provided by operating activities on the Combined Statements of Cash Flows for the year ended December 31, 2017 have decreased by $36 million to reflect the change in presentation.

Simplifying Cash Flow Classification
Effective January 1, 2018, the Company adopted ASU 2016-15 on a retrospective basis. The new standard reduces diversity in practice of how certain cash receipts and cash payments are classified in the statement of cash flows. The new guidance addresses eight specific presentation issues. The Company assessed each of the eight specific presentation issues and the adoption of this ASU did not have a material impact on the Company's Combined Financial Statements.

Recognition and Measurement of Financial Assets and Liabilities
Effective January 1, 2018, the Company adopted ASU 2016-01 on a prospective basis. The new standard addresses certain aspects of recognition, measurement, presentation and disclosure of financial assets and liabilities. Investments in equity securities, excluding equity method and consolidated investments, are no longer classified as trading or available-for-sale securities. All investments in equity securities with readily determinable fair values are classified as investments at fair value through net income. Investments in equity securities without readily determinable fair values are measured using the fair value measurement alternative and are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the fair value measurement alternative are reviewed for indicators of impairment each reporting period. Fair value of financial instruments for disclosure purposes is measured using exit price. The adoption of this accounting update did not have a material impact on the Company's Combined Financial Statements.

Revenue from Contracts with Customers
Effective January 1, 2018, the Company adopted Accounting Standard Update (ASU) 2014-09 on a modified retrospective basis. The new standard was issued with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. It also requires the use of more estimates and judgments than the previous standards along with additional disclosures. For additional details on the adoption of the new standard, see Note 4.

The following ASU's have been issued, but not yet adopted:

Clarifying Interaction between Collaborative Arrangements and Revenue from Contracts with Customers
In November 2018, ASU 2018-18 was issued to provide clarity on when transactions between entities in a collaborative arrangement should be accounted for under the new revenue standard, ASC 606. In determining whether transactions in collaborative arrangements should be accounted under the revenue standard, the update specifies that entities shall apply unit of account guidance to identify distinct goods or services and whether such goods and services are separately identifiable from other promises in the contract. ASU 2018-18 also precludes entities from presenting transactions with a collaborative partner which are not in scope of the new revenue standard together with revenue from contracts with customers. The accounting update is effective January 1, 2020 and early adoption is permitted. The Company is currently assessing the impact of the new standard on the Combined Financial Statements.

Amended Guidance on Cloud Computing Arrangements

In August 2018, ASU 2018-15 was issued to provide guidance on the accounting for implementation costs incurred in a cloud computing arrangement (CCA) that is a service contract. The amendment aligns the accounting for costs incurred to implement a CCA that is a service arrangement with the guidance on capitalizing costs associated with developing or obtaining internal-use software. Additionally ASU 2018-15 specifies that an entity would apply ASC 350-40 to determine which implementation costs related to a hosting arrangement that is a service contract should be capitalized and which should be expensed. Furthermore, the amendments in the update require capitalized costs be amortized on a straight-line basis generally over the term of the arrangement and presented in the same income statement line as fees paid for the hosting service. The new standard also requires that the balance sheet presentation of capitalized implementation costs to be the same as that of the prepayment of fees related to the hosting arrangement, as well as similar consistency in classifications from a cash flow statement perspective. ASU 2018-15 is effective January 1, 2020 and the Company has elected to early adopt the standard as of January 1, 2019, as permitted. The Company does not expect the adoption of this accounting update to have a material impact on the Combined Financial Statements.

Disclosure Effectiveness

In August 2018, the Financial Accounting Standards Board issued two amendments as a part of its disclosure framework project aimed to improve the effectiveness of disclosures in the notes to financial statements.

ASU 2018-14 was issued in August 2018 to improve disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendment modifies ASC 715, Compensation - Retirement Benefits, by adding and removing several disclosure requirements while also clarifying the guidance on current disclosure requirements. ASU 2018-14 is effective January 1, 2021 and entities are permitted to adopt the standard early. The Company is currently assessing the impact of the new standard on the Combined Financial Statements.

ASU 2018-13 was issued to modify the disclosure requirements in ASC 820, Fair Value Measurement. The amendments in ASU 2018-13 eliminate and modify some disclosures, while also adding new disclosures for fair value measurements. This update is effective January 1, 2020, however entities are permitted to early adopt the eliminated or modified disclosures. The Company is currently assessing the impact of the new standard on the Combined Financial Statements.

Accounting for Credit Losses

ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity will recognize as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses.

Further, ASU 2018-19 was issued in November 2018 to clarify that operating lease receivables should be accounted for under the new leases standard, ASC 842, and are not within the scope of ASC 326, Financial Instruments - Credit Losses. Both accounting updates are effective January 1, 2020. The Company is currently assessing the impact of the new standard on the Combined Financial Statements.

Recognition of Leases

ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations. It requires lessees of operating lease arrangements to recognize lease assets and lease liabilities on the statement of financial position and disclose additional key information about lease agreements. The accounting update also replaces the current definition of a lease and requires that an arrangement be recognized as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. The new standard became effective January 1, 2019, in adopting ASC 842, the Company has applied the package of practical expedients offered in connection with this update. Application of the package of practical expedients permits entities not to reassess a) whether any expired or existing contracts contain leases in accordance with the new guidance, b) lease classifications, and c) whether initial direct costs capitalized under current guidance continue to meet the definition of initial direct costs under the new guidance. Under the new lease guidance, the Company has also decided to elect, by class of underlying asset, to not separate non-lease components from the associated lease components of our lessee contract and account for both components as a single lease component.

ASU 2018-01 was issued in January 2018 to address stakeholder concerns about the costs and complexity of complying with the transition provisions of the new lease requirements as they relate to land easements. The amendments provide an optional transition practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under existing guidance. The Company has elected to use this practical expedient in connection with the adoption of the new lease requirements.

In July 2018, ASU 2018-11 was issued to address additional stakeholder concerns regarding the unanticipated costs and complexities associated with the modified retrospective transition method as well as the requirement for lessors to separate components of a contract. Under the new guidance, entities are provided with an additional transition method which allows entities to apply the new standard at the date of adoption and to elect not to recast comparative periods presented. This amendment also permits lessors to combine associated lease and non-lease components within a contract for operating leases when certain conditions are met. The Company elected both of these practical expedients in the adoption of the new lease standard.

The Company has identified all lease contracts existing as at November 30, 2018 and performed detailed evaluations of those lease contracts under the requirements of the transitional guidance. The Company estimates that it will recognize right-of-use lease assets and related lease liabilities for existing operating leases where it is the lessee in the range of $50 million to $75 million, with no impact to the Combined Statements of Earnings or Combined Statements of Cash Flows. This estimate represents the net present value of future lease payments payable under operating lease contracts the Company has entered into as at November 30, 2018, and that have commenced or are scheduled to commence by January 1, 2019. The Company does not expect any adjustments will be made to its accounting for existing lessor contracts as a result of implementing this new standard.

4. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS

Major Services

December 31,	**2018**
(millions of Canadian dollars)	
Gas commodity and distribution revenue - residential	**2,894**
Gas commodity and distribution revenue - commercial and industrial	**1,385**
Storage revenue	**147**
Transportation revenue	**843**
Other revenue	**46**
Total revenue from contracts with customers	**5,315**
Other	**(18)**
Total operating revenues	**5,297**

The Company disaggregates revenue into categories which represent its principal performance obligations because these revenue categories represent the most significant revenue streams, and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Receivables	Contract Liabilities
(millions of Canadian dollars)		
Balance as at January 1, 2018	801	75
Balance as at December 31, 2018	589	63

Receivables represent an unconditional right to consideration where only the passage of time is required before payment of consideration is due and consist of trade accounts receivable, unbilled revenue and other accrued receivable balances.

Contract liabilities represent payments received for performance obligations which have not been fulfilled, under the Company's equal billing and budget billing programs. Revenue recognized during the year ended December 31, 2018 included in contract liabilities at the beginning of the period is $75 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2018 were $63 million.

Performance Obligations

	Nature of Performance Obligation
Gas commodity and distribution revenue	• Supply and delivery of natural gas to customers.
Storage and transportation revenue	• Storage and transportation of natural gas on behalf of customers.
Other revenue	• Other billing and service fees.

The amount of revenue recognized in the current period from performance obligations satisfied in previous periods was a reduction of $12 million, primarily resulting from differences in actual and estimated consumption, as discussed below in *Significant Judgments Made in Recognizing Revenue*. The associated reduction in gas commodity and distribution costs were also recognized in the current period.

Payment Terms

Payments from distribution revenue customers are received on a continuous basis based on established billing cycles. The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. Payments from transportation revenue customers are received on a continuous basis based on established billing cycles, or monthly under long-term transportation capacity contracts. Payments from storage customers are received monthly under long-term storage capacity contracts.

Revenue to be Recognized from Unfulfilled Performance Obligations

Total revenue from performance obligations expected to be fulfilled in future periods is $755 million, of which $442 million is expected to be recognized during the year ending December 31, 2019.

The amounts above reflect revenues expected to be recognized in future periods from unfulfilled performance obligations pursuant to contracts with customers for the purchase of natural gas distribution, transportation and storage services. The Company uses the optional exemption available under ASC 606 whereby certain revenues such as flow through costs charged to customers are recognized at the amount for which the Company has the right to invoice its customers. Those revenues are not included in the amounts above. The Company also uses the optional exemption available under ASC 606 whereby revenues from contracts with customers which have an original expected duration of one year or less are excluded from the amounts above. Variable consideration is excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, the Company considers interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. A significant portion of the Company's operations are subject to regulation and accordingly the amounts above only include, where applicable, revenue for which the underlying rate has been approved by regulation. The revenues excluded from the amounts above, as explained, represent a significant portion of the Company's overall revenues and revenues from contracts with customers.

SIGNIFICANT JUDGEMENTS MADE IN RECOGNIZING REVENUE

Revenue Recognition

Revenues from contracts with customers are generally recognized upon the fulfillment of the performance obligations as described above. Distribution and transportation service revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company’s distribution franchise areas.

A significant portion of the Company’s operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue under such circumstances is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator, which follow the accounting guidance found in *ASC 980 - Regulated Operations*.

Recognition and Measurement of Revenue

Timing of Revenue Recognition

December 31,	**2018**
(millions of Canadian dollars)	
Revenue from products and services transferred over time[1]	**5,246**
Revenue from products transferred at a point in time[2]	**69**
Total revenue from contracts with customers	**5,315**

1 Revenue from distribution, transportation and storage services.
2 Primarily from other revenue.

Performance Obligations Satisfied Over Time

For distribution and transportation services arrangements where the services are simultaneously received and consumed by the customer, the Company recognizes revenue over time using an output method based on volumes of commodities delivered.

Revenue from storage services are recognized as the storage services are provided.

Determination of Transaction Prices

Prices for distribution and transportation services and regulated storage services are prescribed by regulation. Fees for unregulated storage services are determined through negotiations with customers based on market rates. Prices for the natural gas commodity are driven by market prices and the Company has a quarterly rate adjustment mechanism in place that allows for rates to reflect changes in natural gas prices, subject to regulatory approval.

METHOD AND EFFECTS OF ADOPTION

The Company has adopted ASC 606 using the modified retrospective method, whereby prior periods are not restated for the effect of ASC 606. Results for 2018 have been presented as if ASC 606 had been in effect as at January 1, 2018.

The following table presents the effect of the adoption of ASC 606 on the Company's Combined Statement of Earnings for the year ended December 31, 2018 on each affected financial statement line item along with explanations of those effects:

December 31,	**2018**
(millions of Canadian dollars)	
Gas commodity and distribution revenue	**(27)**
Earnings sharing	**(27)**

The Company is required by the terms of its regulated tariff to refund a portion of its earnings in excess of an amount specified by the regulator to its customers, referred to as the Earnings Sharing Mechanism (ESM). Previously, this amount was shown in the Combined Statements of Earnings as an operating expense. Under ASC 606, payments to customers are accounted for as reductions to revenue unless the payment is in exchange for a distinct good or service. Accordingly, payments under the ESM are shown as reductions of revenue in the Combined Statements of Earnings from January 1, 2018 forward. For the year ended December 31, 2018, this change in presentation resulted in a reduction of $27 million in the Gas commodity and distribution revenue and Earnings sharing financial statement line items.

5. ASSETS HELD FOR SALE

In August 2017, EGD entered into an agreement to sell the issued and outstanding shares of its wholly-owned subsidiary, St. Lawrence Gas, for cash of approximately $96 million (US $70 million), minus third-party debt at closing and subject to customary working capital adjustments. The transaction is subject to regulatory approval and certain pre-closing conditions, and is expected to close in 2019. As at December 31, 2018, St. Lawrence Gas was classified as held for sale on the Combined Statements of Financial Position and was measured at the lower of its carrying value and fair value less costs to sell. Included within Assets held for sale, long-term as at December 31, 2018 is $102 million (December 31, 2017 - $94 million) related to Property, plant and equipment, net. No impairment loss was recognized on the classification of St. Lawrence Gas as held for sale. Any gain or loss on the sale will be measured and recorded at the date that the transaction closes.

6. REGULATORY MATTERS

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

The Company is regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act*, (1998), which is part of a package of legislation known as the *Energy Competition Act*, (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario.

The Company records assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities.

RATE APPROVALS

Enbridge Gas Distribution Inc.

EGD’s distribution rates, beginning in 2014 through 2018, were set under a five-year customized incentive regulation (IR) plan. The plan required EGD to update select items in each of 2015 through 2018, in order to establish final allowed revenues and rates. Under the customized IR plan, EGD shared equally with customers, earnings above the annually approved allowed return on equity.

Union Gas Limited
Union Gas' distribution rates, beginning in 2014 through 2018, were set under a five-year IR plan which established new rates at the beginning of each year through the use of a pricing formula, rather than through the examination of revenue and cost forecasts. The IR plan included an earnings sharing mechanism with customers, that permitted Union Gas to fully retain the return on equity from utility operations up to 9.93%, to retain 50% of any earnings between 9.93% and 10.93%, and to retain 10% of any earnings above 10.93%.

St. Lawrence Gas Company, Inc.
St. Lawrence Gas is currently in a rate year ending May 31, 2019, according to the a NYSPSC order establishing a three year rate plan beginning June 1, 2016. In each rate year, St. Lawrence Gas' rates were set using a Cost of Service (COS) methodology. Under COS, revenues are set to recover costs and to earn a rate of return on the deemed common equity component of rate base. Costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, interest and income taxes. Rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Gas costs are not recovered through revenue rates, but are set separately in gas cost rates.

The three year rate plan includes an earnings sharing mechanism that permits St. Lawrence Gas to fully retain the return on equity from operations up to 9.5%, share 50% of any earnings between 9.5% and 10.0% with customers, share 80% of any earnings between10.0% to 10.5% with customers and share 90% of any earnings over 10.5% with customers.

Under COS, it is the responsibility of St. Lawrence Gas to demonstrate to the NYSPSC the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken.

APPROVED RETURNS ON EQUITY
Enbridge Gas Distribution Inc.
EGD's rates for 2018 included an after-tax rate of return on common equity of 9.00% (2017 - 8.78%) based on a 36% (2017 - 36%) deemed common equity component of rate base.

Union Gas Limited
Union Gas' approved after-tax return on common equity is fixed at 8.93% for the five-year IR term based on a 36% deemed common equity component of rate base.

St. Lawrence Gas Company, Inc.
St. Lawrence Gas' approved after-tax rate of return on common equity embedded in rates was 9.0% for the rate year ended May 31, 2019 (fiscal 2017 - 9.0%) based on a 48% (fiscal 2017 - 48%) deemed common equity component of rate base.

APPLICATION TO AMALGAMATE
In November 2017, EGD and Union Gas (together, the Applicants) filed two applications with the OEB consisting of an application to amalgamate in accordance with the OEB's guidance for Mergers, Acquisitions, Amalgamations and Divestitures (MAADs), and an application seeking approval of the rate setting mechanism to be utilized over the deferred rebasing period, both with an effective date of January 1, 2019. Under the OEB's MAADs policy, the Applicants are able to seek to defer rate rebasing, to allow them the opportunity to identify and leverage best practices and implement integrated solutions.

On August 30, 2018, the Applicants received a decision from the OEB (the MAADs Decision) which approved the application to amalgamate. The MAADs Decision also approved the rate setting mechanism to be employed during a five-year deferred rebasing period from 2019 through 2023, after which time rates will be rebased. In accordance with the approved rate setting mechanism, rates in each year of the five-year deferred rebasing period will be set under a price cap mechanism, which includes annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable the inclusion of incremental capital module amounts which allow for the recovery of material discrete incremental capital investments beyond which can be funded through base rates. The MAADs Decision also approved the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires the amalgamated entity to share equally with customers, any earnings in excess of 150 basis points over the OEB approved rate of return on equity. In the fourth quarter of 2018, in accordance with the approved rate setting mechanism, the Applicants filed a rate application seeking approval for the establishment of rates effective January 1, 2019.

On October 15, 2018, Enbridge announced that it would move forward with the amalgamation of EGD and Union Gas. On January 1, 2019, EGD and Union Gas amalgamated and the Company has continued as Enbridge Gas.

FINANCIAL STATEMENT EFFECTS

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	**2018**	2017	Combined Statements of Financial Position	Recovery/Refund Period Ends
(millions of Canadian dollars)				
Current regulatory assets				
Purchase gas variance[1]	**169**	55	AR	2019
Short-term debt[8]	**—**	12	AR	2018
Other current regulatory assets	**124**	152	AR	2019
Total current regulatory assets	**293**	219		
Long-term regulatory assets				
Deferred income taxes - long-term[2]	**1,131**	998	DA	Various
Pension plan receivable[3]	**60**	42	DA	Various
OPEB[4]	**58**	62	DA	Various
Long-term debt[8]	**387**	413	DA	Various
Other long-term regulatory assets	**—**	23	DA	Various
Total long-term regulatory assets	**1,636**	1,538		
Total regulatory assets[5]	**1,929**	1,757		
Current regulatory liabilities				
Site restoration clearance adjustment[6]	**—**	31	AP	2018
Other current regulatory liabilities	**135**	72	AP	2019
Total current regulatory liabilities	**135**	103		
Long-term regulatory liabilities				
Future removal and site restoration reserves[7]	**1,356**	1,296	OLTL	Various
Other long-term regulatory liabilities	**24**	7	OLTL	Various
Total long-term regulatory liabilities	**1,380**	1,303		
Total regulatory liabilities[5]	**1,515**	1,406		

AR – Accounts receivable and other
AP – Accounts payable and other
DA – Deferred amounts and other assets
OLTL – Other long-term liabilities

1 *Purchase gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. The Company has been granted OEB approval to refund this balance to, or collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process.*

2 The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate regulation accounting, this regulatory balance and the related earnings impact would not be recorded.

3 The pension plan balance represents EGD's regulatory offset to the pension liability to the extent the amounts are to be collected in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation accounting, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.

4 The OPEB balance represents EGD's right to recover OPEB costs resulting from the adoption of the accrual basis of accounting for OPEB costs upon transition to US GAAP in 2012. Pursuant to the OEB rate order, the amount as at December 31, 2012 is to be collected in rates over a 20-year period that commenced in 2013. In the absence of rate regulation accounting, this regulatory balance and related earnings impact would not be recorded.

5 All regulatory assets and liabilities are excluded from rate base unless otherwise noted.

6 The site restoration clearance adjustment represents the amount that was determined by the OEB for EGD of previously collected costs for future removal and site restoration that was considered to be in excess of future requirements and was refunded to customers over the customized IR term.

7 Future removal and site restoration reserves result from amounts collected from customers by the Company, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment that is recorded in rates. The balance represents the amount that the Company has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation accounting, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

8 The debt balance represents the Company's regulatory offset to the fair value adjustment to debt pushed down to Union Gas. The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.

OTHER ITEMS AFFECTED BY RATE REGULATION

Operating Cost Capitalization

In the absence of rate regulation accounting, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred.

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation accounting, a portion of such operating costs would be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, were being capitalized to gas mains in accordance with regulatory approval. At December 31, 2018, the net book value of these costs included in gas mains in Property, plant and equipment, net was $110 million (2017 - $118 million). In the absence of rate regulation accounting, some of these costs would be charged to earnings in the year incurred.

WAMS is EGD's integrated work and asset management solution. At December 31, 2018, the net book value of the asset included in intangible assets was $68 million (2017 - $77 million). In the absence of rate regulation accounting, a portion of the original cost of the asset would have been expensed in the period incurred.

Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. Included in gas inventories at December 31, 2018 is $59 million (2017 - $55 million) related to EGD storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation accounting, these costs would be expensed as incurred and inventory would be recorded at the lower of cost or market value.

Depreciation
In the absence of rate regulation accounting, depreciation rates would not have included a charge for future removal and site restoration costs.

7. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2018**	2017
(millions of Canadian dollars)		
Trade receivables	**548**	574
Unbilled revenues	**270**	411
Gas imbalances[1]	**84**	251
Regulatory assets *(Note 6)*	**293**	219
Rebillables receivable	**110**	76
Other	**45**	147
Allowance for doubtful accounts *(Note 15)*	**(38)**	(35)
	1,312	1,643

[1]The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Combined Statements of Financial Position dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

8. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2018**	2017
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	**2.33%**	**8,921**	8,502
Gas services	**2.46%**	**4,983**	4,824
Regulating and metering equipment	**4.14%**	**2,333**	2,243
Storage	**2.46%**	**985**	981
Other operating equipment	**2.94%**	**2,093**	2,053
Land and right-of-way	**0.84%**	**342**	338
Under construction	**—**	**193**	138
		19,850	19,079
Accumulated depreciation		**(5,427)**	(5,123)
		14,423	13,956
Unregulated property, plant and equipment			
Regulating and metering equipment	**2.12%**	**27**	30
Storage	**2.25%**	**411**	395
Other operating equipment	**2.03%**	**74**	74
Land and right-of-way	**1.49%**	**40**	40
Under construction	**—**	**14**	14
		566	553
Accumulated depreciation		**(171)**	(165)
		395	388
Property, plant and equipment, net		**14,818**	14,344

Depreciation expense, including amounts collected for future removal and site restoration costs, was $540 million for the year ended December 31, 2018 (2017 - $476 million).

Included within depreciation expense is $22 million for the year ended December 31, 2018 (2017 - $22 million) in incremental depreciation resulting from push-down accounting *(Note 2)*.

9. INTANGIBLE ASSETS

December 31,	**2018**	2017
(millions of Canadian dollars)		
Intangible assets		
Software and Customer Information System (CIS)	**586**	536
Emission allowances	**—**	638
	586	1,174
Less: Accumulated amortization	**(377)**	(319)
Intangible assets, net	**209**	855

Intangible assets consist primarily of software and emission allowances. From January 1, 2017 through July 3, 2018, emission allowances were purchased by the Company for itself and most of its customers in order to meet greenhouse gas compliance obligations in the province of Ontario. Purchased emission allowances were recorded at their original cost and were not amortized, as they were intended to satisfy compliance obligations as they became due. On October 31, 2018, Bill 4 received Royal Assent from the government of Ontario, providing for the wind down of the Cap and Trade program. This resulted in an elimination of $990 million in emission allowances in the fourth quarter of 2018.

For the year ended December 31, 2018, the weighted average amortization rate for software and CIS was 12.6% (2017 - 15.9%).

Intangible assets include $33 million of work-in-progress as at December 31, 2018 (2017 - $22 million). Total amortization expense for intangible assets was $68 million for the year ended December 31, 2018 (2017 - $78 million). The Company expects aggregate amortization expense for the years ending December 31, 2019 through 2023 of $82 million, $64 million, $39 million, $34 million, and $35 million, respectively.

10. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2018**	2017
(millions of Canadian dollars)		
Regulatory assets *(Note 6)*	**1,636**	1,538
Pension and OPEB assets	**29**	35
Other	**266**	289
	1,931	1,862

11. ACCOUNTS PAYABLE AND OTHER

December 31,	**2018**	2017
(millions of Canadian dollars)		
Accrued liabilities	**449**	391
Trade payables	**253**	240
Gas imbalances[1]	**84**	251
Regulatory liabilities *(Note 6)*	**135**	103
Other	**394**	401
	1,315	1,386

[1]The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Combined Statements of Financial Position dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

12. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2018**	2017
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc.				
Medium-term notes[1]	4.47%	2020-2050	**3,695**	3,695
Debentures	9.85%	2024	**85**	85
Commercial paper and credit facility draws, net			**750**	960
Union Gas Limited				
Medium-term notes	4.11%	2021-2047	**3,290**	3,490
Senior debentures			**—**	75
Debentures	8.65%	2025	**125**	250
Commercial paper and credit facility draws, net			**275**	485
Other[2]			**(40)**	(43)
Fair value adjustment from push down accounting *(Note 1)*			**388**	427
Total debt			**8,568**	9,424
Current maturities			**—**	(412)
Short-term borrowings	2.34%		**(1,025)**	(1,445)
Short-term borrowings from affiliates[3] *(Note 20)*			**—**	—
Long-term debt			**7,543**	7,567
Loans from affiliate companies *(Note 20)*			**950**	375

1 The balance pertaining to St. Lawrence Gas amounting to approximately $10 million as at December 31, 2018 (2017 - $9 million) is presented as Liabilities held for sale, long-term (Note 5) on the Combined Statements of Financial Position.
2 Consists of debt discounts and debt issuance costs.
3 The balance in 2018 pertaining to St. Lawrence Gas amounting to approximately $33 million (2017 - $30 million) is presented as Liabilities held for sale, current (Note 5) on the Combined Statements of Financial Position.

In September 2018, EGD borrowed $300 million from its parent company, Enbridge through a subordinated promissory note at an interest rate of 3.37%, payable quarterly in arrears. This note matures in September 2028.

In October 2018, Union Gas borrowed $650 million from Westcoast Energy Inc., an affiliate under common control, through a subordinated promissory note at an interest rate of 3.65%, payable semi-annually in arrears. This note matures in October 2028.

In November 2017, EGD issued $300 million of thirty-year medium-term notes (MTNs) at an interest rate of 3.51% payable semi-annually in arrears. This MTN matures in November 2047.

In November 2017, Union Gas issued $250 million of ten-year MTNs at an interest rate of 2.88% payable semi-annually in arrears. This MTN matures in November 2027.

In November 2017, Union Gas also issued $250 million of thirty-year MTNs at an interest rate of 3.59% payable semi-annually in arrears. This MTN matures in November 2047.

For the years ending December 31, 2019 through 2023, debentures and medium-term note maturities are $nil, $400 million, $375 million, $125 million and $350 million, respectively. The Company's debentures and medium-term notes bear interest at fixed rates, and interest obligations for the years ending December 31, 2019 through 2023 are $321 million, $319 million, $301 million, $286 million and $276 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2018**	2017
(millions of Canadian dollars)		
Debentures, senior debenture and medium-term notes	**338**	320
Loans from affiliate company *(Note 20)*	**34**	29
Commercial paper and credit facility draws	**16**	13
Other interest and finance costs	**8**	8
Capitalized	**(5)**	(14)
	391	356

In 2018, total interest paid to third parties was $357 million (2017 - $327 million) and total interest paid to affiliates was $34 million (2017 - $29 million).

The Company's borrowings, whether senior debentures or MTNs, are unsecured.

CREDIT FACILITIES

EGD had a $1 billion commercial paper program that was backstopped by committed lines of credit of $1 billion. The issuance of commercial paper and revolving borrowings reduce the amount available under this credit facility. The maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option. In July 2018, EGD extended the term out date of this external credit facility to July 2019, with a maturity date in July 2020.

Union Gas had a $700 million commercial paper program that was backstopped by committed lines of credit of $700 million. The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under this credit facility. The credit facility has a maturity date of April 2021.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2018.

				December 31, 2018	December 31, 2017
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge Gas Distribution Inc.[3]	2020	**1,000**	**750**	**250**	1,000
St. Lawrence Gas Company, Inc.	2019	**18**	**10**	**8**	16
Union Gas Limited[2, 3]	2021	**700**	**275**	**425**	700
Total credit facilities		**1,718**	**1,035**	**683**	1,716

1 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the external credit facility. St. Lawrence Gas draws are shown as Liabilities held for sale, current and long-term on the Combined Statements of Financial Position.

2 The credit facility contains a covenant requiring the debt-to-total capitalization ratio, as defined in the agreement, to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year.

3 On February 7, 2019, the Company extended the term out date of its external credit facility to July 2020, with a maturity date in July 2021 and increased the size of total commitments to $2 billion. The Company's credit facility, through Union Gas was terminated on February 7, 2019.

Credit facilities carried a weighted average standby fee of 0.12% on the unused portion and the draws bear interest at market rates.

DEBT COVENANTS

The Company's credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or terminations of the agreements may result if the Company were to default on payment or violate certain covenants. As at December 31, 2018 the Company was in compliance with all debt covenants.

13. SHARE CAPITAL

At December 31, 2018, the authorized share capital of the Company consisted of an unlimited number of common shares with no par value and a limited number of preference shares.

COMMON SHARES

	2018		2017	
December 31,	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of common shares in millions)				
Enbridge Gas Distribution Inc.				
Balance at beginning of year	**213**	**2,417**	185	1,917
Common shares issued	**20**	**350**	28	500
Return of capital	**—**	**(450)**	—	—
Balance at end of year *(Note 20)*	**233**	**2,317**	213	2,417
Union Gas Limited				
Balance at beginning of year	**58**	**657**	58	657
Common shares issued[1]	**—**	**57**	—	—
Return of capital	**—**	**(1)**	—	—
Balance at end of year *(Note 20)*	**58**	**713**	58	657

1 In February 2018 Union Gas Gas issued 621,866 shares for $57 million. Total Union Gas shares outstanding 58,444,516.

On January 1, 2019, EGD and Union Gas amalgamated to form Enbridge Gas. Enbridge Gas authorized unlimited common shares and Enbridge Energy Distribution Inc. (EEDI), which wholly-owned EGD, was issued 281,881,334 Class A common shares in exchange for 232,749,988 EGD common shares and 621,866 Union Gas Class A common shares. Great Lakes Basin Energy L.P. (GLBE), which owned 99% of Union Gas, was issued 240,020,243 Class B common shares in exchange for 57,822,650 Union Gas common shares. Both classes of common shares are identical in every respect. Dividends cannot be paid to one class without paying dividends on the other.

PREFERENCE SHARES

December 31,		**2018**		2017	
	Authorized	Issued and Outstanding	Amount	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preference shares in thousands)					
Enbridge Gas Distribution Inc.					
Group 2, Series A - C, Cumulative Redeemable Retractable	6,000	**—**	**—**	—	—
Group 2, Series D, Cumulative Redeemable Convertible	4,000	**—**	**—**	—	—
Group 3, Series A - C, Cumulative Redeemable Retractable	6,000	**—**	**—**	—	—
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible[1]	4,000	**—**	**—**	4,000	100
Group 4	10,000	**—**	**—**	—	—
Group 5	10,000	**—**	**—**	—	—
Union Gas Limited					
Class A	202				
Series A, 5.5% Cumulative Redeemable[2]		**—**	**—**	48	3
Series B, 6% Cumulative Redeemable[3]		**—**	**—**	90	5
Series C, 5% Cumulative Redeemable[2]		**—**	**—**	50	2
Class B, Series 10, 4.88% Cumulative Redeemable Convertible[4]	Unlimited	**—**	**—**	4,000	100
			—		210

1 *Floating adjustable cumulative cash dividends on the Group 3, Series D preference shares are payable at 80% of the prime rate. EGD has the option to redeem the shares for $25.50 per share if the preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.*

2 *Class A, Series A and Class A, Series C preference shares are cumulative and redeemable at $50.50 per share. Union Gas is obligated to offer to purchase $170,000 of Series A and $140,000 of series C shares annually at the lowest price obtainable, but not exceeding $50 per share.*

3 *Class A, Series B preference shares are cumulative and redeemable at $55 per share at the option of Union Gas.*

4 *Class B, Series 10 preference shares are cumulative and redeemable at $25 per share at the option of Union Gas and, at the option of the holders, convertible back into Series 11 shares once every five years commencing January 1, 2014. The holders of the Class B, Series 10 preference shares did not exercise their option on January 1, 2014. Union Gas may redeem at any time at all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2018.*

On November 29, 2018, EGD redeemed all outstanding Group 3, Series D preference shares for $25.00 per share and Union Gas redeemed all outstanding preference shares for the following amounts per share: Class A, Series A - $50.50; Class A, Series B - $55.00; Class A, Series C - $50.50 and Class B, Series 10 - $25.00. On January 1, 2019, all classes of the preference shares were canceled and an unlimited number of new preference shares were authorized, however no preference shares have been issued at this time.

14. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

Changes in AOCI for the years ended December 31, 2018 and 2017 are as follows:

	2018			
	Cash Flow Hedges	Cumulative Translation Adjustment	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)				
Balance at January 1, 2018	**(8)**	**1**	**(32)**	**(39)**
Other comprehensive loss retained in AOCI	**(6)**	**—**	**(20)**	**(26)**
Other comprehensive loss reclassified to earnings	**4**	**4**	**—**	**8**
	(10)	**5**	**(52)**	**(57)**
Tax Impact				
Income tax on amounts retained in AOCI	**2**	**—**	**5**	**7**
Income tax on amounts reclassified to earnings	**(1)**	**—**	**—**	**(1)**
	1	**—**	**5**	**6**
Balance at December 31, 2018	**(9)**	**5**	**(47)**	**(51)**

	2017			
	Cash Flow Hedges	Cumulative Translation Adjustment	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)				
Balance at January 1, 2017	(11)	4	(8)	(15)
Other comprehensive loss retained in AOCI	—	(3)	(32)	(35)
Other comprehensive loss reclassified to earnings	4	—	—	4
	(7)	1	(40)	(46)
Tax Impact				
Income tax on amounts retained in AOCI	—	—	8	8
Income tax on amounts reclassified to earnings	(1)	—	—	(1)
	(1)	—	8	7
Balance at December 31, 2017	(8)	1	(32)	(39)

15. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and OCI are subject to movements in natural gas prices, foreign exchange rates and interest rates (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customers; therefore, the net exposure to the Company is zero.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. The Company generates certain revenues and holds a subsidiary that is denominated in USD. As a result, the Company's earnings, cash flows, and OCI are exposed to fluctuations resulting from USD exchange rate variability.

The Company implemented a policy to hedge a portion of USD denominated unregulated storage revenue exposures. Qualifying derivative instruments are used to hedge anticipated USD denominated revenues and to manage variability in cash flows.

A portion of the Company's purchases of natural gas are denominated in USD and as a result there is exposure to fluctuations in the exchange rate of the USD against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the Company has no net exposure to movements in the foreign exchange rate on natural gas purchases.

The Company did not have any outstanding derivative instruments relating to net investment hedges as at December 31, 2018 and December 31, 2017.

Interest Rate Risk
The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 2.3%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.7%.

The Company's portfolio mix of fixed and variable rate debt instruments is monitored by its ultimate parent company, Enbridge. The Company does not typically manage the fair value of its debt instruments.

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the financial statement line item in the Combined Statements of Financial Position and carrying value of the Company's derivative instruments.

The Company generally has a common practice of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Combined Statements of Financial Position.

December 31, 2018	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable and other					
Interest rate contracts	**(2)**	**—**	**(2)**	**—**	**(2)**
	(2)	**—**	**(2)**	**—**	**(2)**
Other long-term liabilities					
Foreign exchange contracts	**(1)**	**—**	**(1)**	**—**	**(1)**
Interest rate contracts	**(3)**	**—**	**(3)**	**—**	**(3)**
	(4)	**—**	**(4)**	**—**	**(4)**
Total net derivative asset/(liability)					
Foreign exchange contracts	**(1)**	**—**	**(1)**	**—**	**(1)**
Interest rate contracts	**(5)**	**—**	**(5)**	**—**	**(5)**
	(6)	**—**	**(6)**	**—**	**(6)**

December 31, 2017	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Other long-term assets					
Foreign exchange contracts	1	—	1	—	1
Total net derivative assets					
Foreign exchange contracts	1	—	1	—	1

The following table summarizes the maturity and notional principal or quantity outstanding related to the Company's derivative instruments.

December 31, 2018	2019	2020	2021	2022	2023	Thereafter
Foreign exchange contracts - United States dollar forwards - sell *(millions of USD)*	**4**	**3**	**3**	**1**	**—**	**—**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**412**	**542**	**379**	**18**	**—**	**—**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**350**	**180**	**275**	**—**	**—**	**—**

The Effect of Derivative Instruments on the Combined Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's combined earnings and comprehensive income, before the effect of income taxes.

Year ended December 31,	**2018**	2017
(millions of Canadian dollars)		
Amount of unrealized loss recognized in OCI cash flow hedges		
Interest rate contracts	**(5)**	—
Foreign exchange contracts	**(1)**	—
	(6)	—
Amount of loss reclassified from AOCI to earnings *(effective portion)*		
Interest rate contracts[1]	**(4)**	(4)
	(4)	(4)
Amount of loss reclassified from AOCI to earnings *(ineffective portion)*		
Interest rate contracts[1]	**—**	—
	—	—

1 Reported within Interest expense in the Combined Statements of Earnings.

The Company estimates a loss of $1 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on interest and foreign exchange rates in effect when derivative contracts that are currently outstanding mature.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under committed credit facilities and long-term debt, which includes debentures and medium term notes (MTNs) and, if necessary, additional liquidity is available through intercompany transactions with its ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable the Company to fund all anticipated requirements. The Company also maintains committed credit facilities with a diversified group of banks and institutions. The Company is in compliance with all the terms and conditions of its committed credit facilities as at December 31, 2018. As a result, all credit facilities are available to the Company and the banks are obligated to fund the Company under the terms of the facilities.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts, which totaled $38 million at December 31, 2018 (December 31, 2017 - $35 million).

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate.

Entering into derivative financial instruments may also result in exposure to credit risk. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

The Company has group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments:

December 31,	**2018**	2017
(millions of Canadian dollars)		
Canadian financial institutions	—	1
Other	—	—
	—	1

FAIR VALUE MEASUREMENTS
The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS
The Company categorizes its derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1
Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company does not have any derivative instruments classified as Level 1.

Level 2
Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps for which observable inputs can be obtained.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support a Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2018, the Company had Level 2 derivative assets with fair value of $nil (2017 - $1 million) and Level 2 derivative liabilities with fair value of $6 million (2017 - $nil). The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers between levels as at December 31, 2018 or December 31, 2017.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded, unless actively quoted market prices are not available for fair value measurement in which case these investments are recorded at the fair value measurement alternative. The Company's investment in IPL System Inc. (IPL), an affiliate company, was recorded at fair value. In December 2018, IPL redeemed all of its Class D preference shares held by the EGD for $825 million. As at December 31, 2018, the fair value of the investment was $nil (2017 - $825 million). The fair value of the Company's investment was classified as a Level 2 measurement and as at December 31, 2018 and 2017 the fair value approximated its cost and redemption value and therefore no amount was recognized in net income.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2018, the Company's long-term debt, including the current portion had a carrying value of $7,195 million (2017 - $7,595 million) before debt issue costs and a fair value of $7,855 million (2017 - $8,690 million).

The fair value of other financial assets and liabilities other than derivative instruments and long-term debt approximate their cost due to the short period to maturity.

16. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2018**	2017
(millions of Canadian dollars)		
Earnings before income taxes	**625**	390
Federal statutory income tax rate	**15.0%**	15.0 %
Federal income taxes at statutory rate	**94**	59
Increase/(decrease) resulting from:		
Provincial and state income taxes	**(4)**	(17)
Effects of rate regulated accounting[1]	**(56)**	(63)
Non-taxable intercompany distributions[1]	**(9)**	(9)
Part VI.1 tax, net of federal Part I tax deduction[1]	**31**	6
Investment in foreign subsidiaries held for sale *(Note 5)*	**1**	4
Other[2]	**—**	3
Income tax expense/(recovery)	**57**	(17)
Effective income tax rate	**9.1%**	(4.4)%

1 The provincial tax component of these items is included in "Provincial and state income taxes" above.

2 Included in "Other" are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals and entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2018**	2017
(millions of Canadian dollars)		
Earnings before income taxes		
Canada	**620**	386
United States	**5**	4
	625	390
Current income taxes		
Canada	**88**	27
United States	**—**	—
	88	27
Deferred income taxes		
Canada	**(32)**	(45)
United States	**1**	1
	(31)	(44)
Income tax expense/(recovery)	**57**	(17)

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2018**	2017
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**1,395**	1,292
Regulatory assets	**300**	263
Deferrals	**20**	44
Other	**10**	5
Total deferred income tax liabilities	**1,725**	1,604
Deferred income tax assets		
Future removal and site restoration reserves	**364**	345
Retirement and postretirement benefits	**12**	5
Minimum tax credits	**24**	18
Loss carryforwards	**—**	13
Financial derivatives	**3**	3
Other	**3**	4
Total deferred income tax assets	**406**	388
Net deferred income tax liabilities	**1,319**	1,216

In 2017, the investment in St. Lawrence Gas was classified as held for sale. The Company is no longer asserting permanent reinvestment for this foreign subsidiary's earnings. As such, it recorded a deferred tax liability of $6 million as at December 31, 2018 (2017 - $4 million) on the difference between the carrying value of this foreign subsidiary and its corresponding tax basis. This difference is largely a result of unremitted earnings and currency translation adjustments.

The Company and its subsidiaries are subject to taxation in Canada and the Unites States. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario). The Company is open to examination by Canadian tax authorities for the 2012 to 2018 tax years. The Company is currently under examination for income tax matters in Canada for the 2015 to 2017 tax years.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2018**	2017
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**45**	38
Gross increases for tax positions of current year	**3**	3
Gross increases for tax positions of prior years	**—**	7
Gross decreases for tax positions of prior years	**(6)**	(2)
Settlements	**(1)**	—
Lapses of statute of limitations	**(2)**	(1)
Unrecognized tax benefits at end of year	**39**	45

The unrecognized tax benefits as at December 31, 2018, if recognized, would affect the Company's effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its Combined Financial Statements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the years ended December 31, 2018 included $nil (2017 - $nil) recoveries, respectively, of interest and penalties. As of December 31, 2018 and 2017, interest and penalties of $1 million and $1 million, respectively, have been accrued.

17. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

Substantially all of the Company's employees participate in registered, contributory, and non-contributory pension plans which provide defined benefit and/or defined contribution pension benefits. Certain of the Company's employees are also members of supplemental pension plans that provide pension benefits in excess of the benefits provided in the registered plans.

Defined Benefit Plans

Benefits payable from the defined benefit component of the members' plans are based on each plan member's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan member's retirement. The Company's contributions are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities.

Defined Contributions

Contributions are based on each plan member's current eligible remuneration and may also be based on age and years of service. For the defined contribution component of the plans, benefit costs equal amounts required to be contributed by the Company.

OTHER POSTRETIREMENT BENEFITS

OPEB primarily includes supplemental health and dental, health spending accounts and life insurance coverage for qualifying retired employees, which are provided on a non-contributory basis. The OPEB plans are not funded.

BENEFIT OBLIGATIONS AND FUNDED STATUS

The following table details the changes in the benefit obligation, the fair value of plan assets and the recorded assets or liabilities for the defined benefit component of the pension and OPEB plans.

December 31,	Pension 2018	Pension 2017	OPEB 2018	OPEB 2017
(millions of Canadian dollars)				
Change in benefit obligation				
Benefit obligation at beginning of year	**2,115**	1,098	**175**	123
Service cost	**58**	49	**3**	3
Interest cost	**68**	60	**6**	6
Actuarial (gain)/loss	**(73)**	86	**(25)**	3
Employee contributions	**9**	4	**—**	—
Benefits paid	**(97)**	(92)	**(7)**	(6)
Balances transferred from Union Gas *(Note 1)*	**—**	926	**—**	62
Net transfer in/out	**(3)**	—	**—**	—
Other	**3**	(16)	**1**	(16)
Benefit obligation at end of year[1]	**2,080**	2,115	**153**	175
Change in plan assets				
Fair value of plan assets at beginning of year	**1,991**	998	**—**	17
Actual return on plan assets	**(15)**	166	**—**	2
Employer's contributions	**36**	61	**7**	6
Employee contributions	**9**	4	**—**	—
Benefits paid	**(97)**	(92)	**(7)**	(6)
Balances transferred from Union Gas *(Note 1)*	**—**	862	**—**	—
Other	**(1)**	(8)	**—**	(19)
Fair value of plan assets at end of year	**1,923**	1,991	**—**	—
Underfunded status at end of year	**(157)**	(124)	**(153)**	(175)
Presented as follows:				
Deferred amounts and other assets *(Note 10)*	**29**	35	**—**	—
Accounts payable and other *(Note 11)*	**(4)**	(2)	**(7)**	(8)
Other long-term liabilities *(Note 19)*	**(182)**	(157)	**(146)**	(167)

1 For pension plans, the benefit obligation is the projected obligation. For OPEB plans, the benefit obligations is the accumulated postretirement benefit obligation. The accumulated benefit obligation for the Company's pension plans was $1,939 million as at December 31, 2018 (2017 - $1,968 million).

At December 31, 2018, pension plans with accumulated benefit obligations in excess of the fair value of plan assets had projected benefit obligations of $595 million (2017 - $596 million), accumulated benefit obligations of $537 million (2017 - $536 million) and plan assets with a fair value of $465 million (2017 - $486 million).

AMOUNTS RECOGNIZED IN OTHER COMPREHENSIVE INCOME

The net actuarial loss and prior service cost included in AOCI, before tax, was $74 million relating to the pension plans and the net actuarial gain included in AOCI, before tax, was $11 million relating to the OPEB plans as at December 31, 2018 (2017 - loss of $30 million and loss of $13 million, respectively).

NET BENEFIT COST RECOGNIZED

The components of net benefit cost and other amounts recognized in pre-tax OCI related to the pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2018**	2017	**2018**	2017
(millions of Canadian dollars)				
Service cost	**58**	49	**3**	3
Interest cost	**68**	60	**6**	6
Expected return on plan assets	**(130)**	(108)	**(1)**	(1)
Amortization of actuarial loss and prior service cost	**14**	17	**—**	—
Net defined benefit and OPEB costs	**10**	18	**8**	8
Defined contribution benefit costs	**6**	7	**—**	—
Net benefit cost recognized in Earnings	**16**	25	**8**	8
Amount recognized in OCI:				
Net actuarial loss arising during the year	**—**	—	**—**	2
Total amount recognized in OCI	**—**	—	**—**	2
Total amount recognized in Comprehensive income	**16**	25	**8**	10

The Company estimates that approximately $17 million related to pension plans and OPEB plans as at December 31, 2018 will be reclassified from AOCI into earnings in the next 12 months.

Pension and OPEB costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension and OPEB costs due to the regulatory mechanism in place.

Regulatory adjustments were recorded in the Combined Statements of Earnings, the Combined Statements of Comprehensive Income and the Combined Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers, respectively, in future rates. For the years ended December 31, 2018 and December 31, 2017, there were nominal differences between pension expense for accounting purposes and pension expense for ratemaking purposes.

ACTUARIAL ASSUMPTIONS

The weighted average assumptions made in the measurement of the benefit obligations and net benefit cost of the pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2018**	2017	**2018**	2017
Benefit obligations				
Discount rate	**3.8%**	3.6%	**3.8%**	3.6%
Rate of salary increase	**3.1%**	3.1%	**3.3%**	3.2%
Net benefit cost				
Discount rate - service cost	**3.7%**	4.1%	**3.7%**	4.1%
Discount rate - interest cost	**3.6%**	3.8%	**3.6%**	3.9%
Rate of return on plan assets	**6.5%**	6.4%	**0.0%**	0.0%
Rate of salary increase	**3.1%**	3.2%	**3.2%**	3.5%

The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

ASSUMED HEALTH CARE COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	2018	2017
Health care cost trend rate assumed for next year	**4.0%**	5.4%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	**4.0%**	4.4%
Year that the rate reaches the ultimate trend rate	**2034**	2034

A 1% point change in the assumed health care cost trend rate would have the following effects for the year ended and as at December 31, 2018:

	1% Point Increase	1% Point Decrease
(in millions of dollars)		
Effect on total service and interest costs	1	(1)
Effect on accumulated postretirement benefit obligation	(11)	(9)

PLAN ASSETS

The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the Company's operating environment and financial situation and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The asset allocation targets and major categories of plan assets are as follows:

		December 31,	
Asset Category	Target Allocation	**2018**	2017
Equity securities	40%	**45.7%**	52.9%
Fixed income securities	36%	**37.2%**	36.9%
Other	24%	**17.1%**	10.2%

The following table summarizes the fair value of the plan assets for the Company's pension and OPEB plans recorded at each fair value hierarchy level.

	2018				2017			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension Benefits								
Cash and cash equivalents	**66**	**—**	**—**	**66**	19	—	—	19
Equity securities								—
United States	**—**	**—**	**—**	**—**	208	—	—	208
Canada	**324**	**—**	**—**	**324**	477	—	—	477
Global	**554**	**—**	**—**	**554**	85	283	—	368
Fixed income securities								—
Government	**402**	**—**	**—**	**402**	389	—	—	389
Corporate	**281**	**—**	**32**	**313**	345	—	—	345
Infrastructure and real estate[4]	**—**	**—**	**266**	**266**	—	—	178	178
Forward currency contracts	**—**	**(10)**	**—**	**(10)**	—	(5)	—	(5)
	1,627	**(10)**	**298**	**1,915**	1,523	278	178	1,979
Non-financial instruments	**—**	**—**	**—**	**8**	—	—	—	12
Total pension plan assets at fair value	**—**	**—**	**—**	**1,923**	—	—	—	1,991

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair values of the infrastructure and real estate investments are established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2018**	2017
(millions of Canadian dollars)		
Balance at beginning of year	**178**	153
Unrealized and realized gains	**39**	17
Purchases and settlements, net	**81**	8
Balance at end of year	**298**	178

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2019	2020	2021	2022	2023	2024- 2028
(millions of Canadian dollars)						
Pension	101	104	107	110	113	607
OPEB	7	7	8	8	8	43

In 2019, the Company expects to contribute approximately $41 million and $7 million to the pension plans and OPEB plans, respectively.

18. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2018**	2017
(millions of Canadian dollars)		
Accounts receivable and other	**238**	(212)
Accounts receivable from affiliates	**25**	(24)
Regulatory assets *(Note 6)*	**(59)**	22
Gas inventory	**(54)**	(9)
Deferred amounts and other assets	**24**	11
Accounts payable and other	**36**	(73)
Accounts payable to affiliates	**(29)**	40
Regulatory liabilities *(Note 6)*	**53**	(24)
Other long-term liabilities	**(8)**	(78)
Cap and trade compliance liability	**387**	603
Assets held for sale	**(12)**	(3)
	601	253

19. OTHER LONG-TERM LIABILITIES

December 31,	**2018**	2017
(millions of Canadian dollars)		
Regulatory liabilities *(Note 6)*	**1,380**	1,303
Cap and trade compliance liability[1]	**—**	603
Pension and OPEB liabilities	**328**	324
Other	**65**	62
	1,773	2,292

1 Under cap and trade regulation in the Province of Ontario, the Company had been required to meet greenhouse gas obligations and had been purchasing emission allowances for itself and most of its customers to satisfy those obligations. On October 31, 2018, Bill 4 received Royal Assent from the government of Ontario, providing for the wind down of the Cap and Trade program. This resulted in an elimination of $990 million in the cap and trade compliance liability in the fourth quarter of 2018.

20. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. Other than the amalgamation of EGD and Union Gas for which all intercompany transactions and balances have been eliminated, the Company's transactions with related parties, are as follows:

Year ended December 31,	**2018**	2017
(millions of Canadian dollars)		
Enbridge Energy Distribution Inc.		
Common share dividends declared	**542**	600
Great Lakes Basin Energy L.P.		
Common share dividends declared	**223**	—
IPL System Inc.		
Dividend income	**60**	63
Interest expense *(Note 12)*	**26**	27
Enbridge		
Charges for centralized services	**72**	49
Part VI.1 tax reimbursement *(Note 16)*	**3**	—
Interest expense *(Note 12)*	**3**	—
Westcoast Energy Inc.		
Interest expense *(Note 12)*	**5**	—
Tidal Energy Marketing Inc.		
Purchase of natural gas	**88**	54
Revenue from optimization services	**4**	9
Revenue from storage and transportation services	**8**	6
Tidal Energy Marketing (U.S.) LLC		
Purchase of natural gas	**68**	61
Gazifère Inc.		
Revenue from wholesale service, including gas sales	**30**	30
Vector Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	**26**	31
Other related entities		
Purchase of natural gas, storage and transportation services	**30**	11
Purchase of treasury and other management services	**—**	10

The Company had related party balances as follows:

December 31,	**2018**	2017
(millions of Canadian dollars)		
Common share ownership from parent company		
Enbridge Energy Distribution Inc.	**2,373**	2,417
Great Lakes Basin Energy L.P.	**657**	657
Investment in affiliate company		
IPL System Inc.	**—**	825
Dividend receivable	**—**	5
Loans from affiliate company		
IPL System Inc.	**—**	375
Interest payable	**—**	9
Note payable to affiliate company		
Westcoast Energy Inc.	**650**	—
Enbridge	**300**	—
Enbridge (U.S.) Inc.	**33**	30
Other accounts receivable/(payable)		
Other related entities, net	**(33)**	(31)

Financing Transactions

In December 2018, IPL, an affiliate under common control, redeemed all of its Class D, non-voting, redeemable, retractable preference shares held by EGD for $825 million. The investment resulted in a weighted average dividend yield of 7.6% as at December 31, 2018.

In December 2018, EGD repaid its two loans outstanding to IPL and all related accrued interest for a total of $376 million.

In September 2018, EGD borrowed $300 million from its parent company, Enbridge Inc. through a subordinated promissory note at an interest rate of 3.37% payable quarterly in arrears. This note matures in September 2028.

In October 2018, Union Gas borrowed $650 million from Westcoast Energy Inc., an affiliate under common control, through a subordinated promissory note at an interest rate of 3.65% payable semi-annually in arrears. This note matures in October 2028.

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 1.1% and is payable on demand.

In February 2018, Union Gas issued 622 thousand shares to EEDI for $57 million. Additionally, Union Gas reduced its stated capital by $1 million for the purposes of returning capital to EEDI. In December 2018, EGD issued 19 million shares to EEDI for $350 million. Additionally, EGD reduced its stated capital by $450 million in cash for the purpose of returning capital to EEDI.

Centralized Services

Enbridge performs centralized corporate functions for the Company, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. The Company reimburses Enbridge for the expenses to provide these services based on the cost of actual services provided or using various allocation methodologies.

Part VI.1 Tax Reimbursement
The Company entered into an agreement with Enbridge for the transfer of Part VI.1 tax and the related Part I tax deduction. The Company received a $3 million non-taxable reimbursement relating to the transfer with EGD receiving $1 million and Union Gas receiving $2 million.

Natural Gas Purchases
The Company contracted for the purchase of natural gas from various affiliates, including Tidal Energy Marketing Inc., and Tidal Energy Marketing (U.S.) LLC., at prevailing market prices under normal trade terms. Contractual obligations under the related party contracts are 2019 to 2020 - $2 million, 2021 to 2022 - $nil, and thereafter - $nil.

Optimization Services
The Company provides pipeline and storage optimization services to Tidal Energy Marketing Inc., an affiliated entity under common control.

Wholesale Service
These gas procurement and transportation services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Storage and Transportation Services
The Company contracted for natural gas transportation services from various affiliates, including Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), NEXUS Gas Transmission (U.S.) LLC, and Sarnia Airport Storage Pool Limited Partnership. Contractual obligations under the related party contracts are 2019 to 2020 - $483 million, 2021 to 2022 - $320 million and thereafter - $1,219 million.

Other Transactions
The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides administrative and other services to certain related entities under common control and records recoveries from these affiliates. The Company recovers the expenses to provide these services based on the cost of actual services provided or using various allocation methodologies. Cost recoveries are recorded as a reduction to Operating and administrative expense in the Combined Statements of Earnings.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a monthly basis.

21. GUARANTEES

In the normal course of conducting business, the Company issues financial guarantees to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Combined Statements of Financial Position. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments. While these agreements may specify a maximum potential exposure, or a specified duration, there are circumstances where the amount and duration are unlimited. The guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

22. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
At December 31, 2018, the Company had commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Operating leases[1]	58	7	6	6	6	6	27
Right-of-way commitments[2]	410	7	7	7	7	7	375
Purchase of services, pipe and other materials, including transportation[3,4]	6,891	1,780	1,016	696	524	347	2,528
	7,359	1,794	1,029	709	537	360	2,930

1 Included in these amounts are building, facility and storage pool leases.

2 Included in these amounts are right-of-way payments, estimated to be approximately $7 million per year, related to cancellable gas storage lease payments that are reasonably likely to occur over the remaining life of all storage reservoirs.

3 Includes capital and operating commitments.

4 Includes: firm capacity payments that provide the Company with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software and consulting or advisory services; customer care services; and contractual obligations for engineering, procurement and construction costs for pipeline projects. Due to a timing uncertainty, all procurement obligations have been included in 2019 as the Company is unable to reasonably estimate the payments due by period.

The Company and certain affiliates, in aggregate, have access to $100 million of letters of credit that they can issue. The total outstanding letters of credit that related to the Company as at December 31, 2018 was $12 million.

ENVIRONMENTAL
The Company is subject to various federal, provincial, state and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on the Company.

Environmental risk is inherent to natural gas pipeline operations, and the Company is, at times, subject to environmental remediation at various contaminated sites. The Company manages this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that the Company is unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, the Company will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of the Company.

Former Manufactured Coal Gas Plant Sites
The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. EGD was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on EGD. It remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, EGD and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with EGD. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

In its fiscal 2003 Rate Case, EGD sought OEB approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with a then current MGP claim and any future MGP claims that may be advanced. With respect to EGD's 2006 to 2018 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation, isolation, and containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

Hamilton Contaminated Site
In April 2016, the Ontario Ministry of the Environment, Conservation and Parks (MECP), formerly the Ministry of the Environment and Climate Change issued a Director's Order (Order) naming Union Gas, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of Union Gas in Hamilton. In May 2016, Union Gas appealed the Order, and in June 2016, the Environmental Review Tribunal (Tribunal), on consent of the MECP's Director, stayed the application of parts of the Order. The Tribunal has extended the stay of the Order several times, which has allowed the owner of the property (with the cooperation of the adjacent owners) to prepare a plan of action, including discussions with the MECP and other neighbours (City of Hamilton and Infrastructure Ontario). The Company continues to monitor the matter, and to cooperate with the owner of the source property, the MECP and other adjacent owners. The risk of material environmental liability is unknown at this time.

TAX MATTERS
The Company maintains tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATION
The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's financial position or results of operations.

ENBRIDGE GAS INC.
(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2019

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Gas Inc.

Financial Reporting
Management of Enbridge Gas Inc. (the Company) is responsible for the accompanying Consolidated Financial Statements. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors is responsible for all aspects related to governance of the Company. The Company does not have an Audit Committee, having received an exemption from such requirement.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare Consolidated Financial Statements for external reporting purposes in accordance with U.S. GAAP and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, have conducted an audit of the Consolidated Financial Statements of the Company in accordance with Canadian generally accepted auditing standards and have issued an unqualified audit report, which is accompanying the Consolidated Financial Statements.

(Signed)

Cynthia L. Hansen
President

(Signed)

Cassell V. Kincaid
Vice President, Finance

February 14, 2020

Independent auditor's report

To the Shareholders of Enbridge Gas Inc.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Inc. (the Company) as at December 31, 2019 and 2018, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America (US GAAP).

What we have audited
The Company's financial statements comprise:

- the consolidated statements of earnings for the years ended December 31, 2019 and 2018;
- the consolidated statements of comprehensive income for the years ended December 31, 2019 and 2018;
- the consolidated statements of shareholders' equity for the years ended December 31, 2019 and 2018;
- the consolidated statements of cash flows for the years ended December 31, 2019 and 2018;
- the consolidated statements of financial position as at December 31, 2019 and 2018; and
- the notes to the consolidated financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above when it becomes available and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company’s financial reporting process.

Auditor’s responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor’s report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Ontario
February 14, 2020

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2019**	2018
(millions of Canadian dollars)		
Operating revenues *(Notes 4 and 22)*		
Gas commodity and distribution revenue	**4,152**	4,242
Storage and transportation revenue	**836**	972
Other revenue	**87**	83
Total operating revenues	**5,075**	5,297
Operating expenses		
Gas commodity and distribution costs *(Note 22)*	**2,334**	2,676
Operating and administrative *(Notes 16, 18, 19 and 22)*	**1,109**	1,077
Depreciation and amortization *(Notes 8 and 9)*	**638**	608
Total operating expenses	**4,081**	4,361
Operating income	**994**	936
Other income *(Notes 5, 18 and 22)*	**20**	80
Interest expense, net *(Notes 12, 15 and 22)*	**(400)**	(391)
Earnings before income taxes	**614**	625
Income tax expense *(Note 17)*	**(58)**	(57)
Earnings	**556**	568
Preference share dividends	**—**	(6)
Earnings attributable to common shareholders	**556**	562

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2019**	2018
(millions of Canadian dollars)		
Earnings	**556**	568
Other comprehensive income/(loss), net of tax *(Notes 14 and 15)*		
Change in unrealized loss on cash flow hedges	**(37)**	(4)
Reclassification to earnings of realized loss on cash flow hedges	**4**	3
Recognition of regulatory offset (*Note 14)*	**55**	—
Actuarial loss on pension plans and other postretirement benefits (OPEB) *(Note 18)*	**(12)**	(15)
Foreign currency translation adjustment	**(5)**	4
Other comprehensive income/(loss), net of tax	**5**	(12)
Comprehensive income	**561**	556
Preference share dividends	**—**	(6)
Comprehensive income attributable to common shareholders	**561**	550

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Preference shares	Common shares *(Note 13)*	Additional paid-in capital	Deficit	Accumulated other comprehensive loss *(Note 14)*	Total
(millions of Canadian dollars)						
December 31, 2018	**—**	**3,030**	**7,253**	**(339)**	**(51)**	**9,893**
Earnings attributable to common shareholders	**—**	**—**	**—**	**556**	**—**	**556**
Other comprehensive income, net of tax	**—**	**—**	**—**	**—**	**5**	**5**
Capital contribution *(Note 22)*	**—**	**800**	**—**	**—**	**—**	**800**
Return of capital *(Note 22)*	**—**	**(313)**	**—**	**—**	**—**	**(313)**
Common shares dividends declared *(Note 22)*	**—**	**—**	**—**	**(937)**	**—**	**(937)**
December 31, 2019	**—**	**3,517**	**7,253**	**(720)**	**(46)**	**10,004**
December 31, 2017	210	3,074	7,253	(136)	(39)	10,362
Preference shares redeemed	(210)	—	—	—	—	(210)
Earnings attributable to common shareholders	—	—	—	562	—	562
Other comprehensive loss, net of tax	—	—	—	—	(12)	(12)
Common shares issued *(Note 22)*	—	407	—	—	—	407
Return of capital *(Note 22)*	—	(451)	—	—	—	(451)
Common shares dividends declared *(Note 22)*	—	—	—	(765)	—	(765)
December 31, 2018	—	3,030	7,253	(339)	(51)	9,893

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2019**	2018
(millions of Canadian dollars)		
Operating activities		
Earnings	**556**	568
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization *(Notes 8 and 9)*	**638**	608
Deferred income tax expense *(Note 17)*	**(31)**	(31)
Net defined pension and other postretirement benefit obligations (OPEB) costs *(Note 18)*	**(17)**	(26)
Loss on disposition *(Note 5)*	**10**	—
Other	**5**	6
Changes in operating assets and liabilities *(Note 20)*	**116**	601
Net cash provided by operating activities	**1,277**	1,726
Investing activities		
Proceeds from wind down of investment in affiliate	**—**	825
Capital expenditures	**(1,073)**	(914)
Additions to intangible assets	**(36)**	(413)
Proceeds from disposition *(Note 5)*	**72**	—
Net cash used in investing activities	**(1,037)**	(502)
Financing activities		
Net change in short-term borrowings *(Note 12)*	**(127)**	(420)
Short-term repayments to affiliates *(Note 22)*	**(32)**	—
Net change in long-term borrowings from affiliates *(Notes 12 and 22)*	**(300)**	575
Term note issuances, net of issue costs *(Note 12)*	**697**	—
Term note repayments *(Note 12)*	**—**	(400)
Common shares issued *(Notes 13 and 22)*	**—**	407
Common share dividends *(Note 22)*	**(937)**	(765)
Preference shares redeemed	**—**	(210)
Preference share dividends	**—**	(7)
Capital contribution received *(Notes 13 and 22)*	**800**	—
Return of capital *(Notes 13 and 22)*	**(313)**	(451)
Net cash used in financing activities	**(212)**	(1,271)
Net increase/(decrease) in cash, cash equivalents and restricted cash	**28**	(47)
Cash, cash equivalents and restricted cash at beginning of year	**49**	96
Cash, cash equivalents and restricted cash at end of year	**77**	49
Supplementary cash flow information		
Cash paid/(received) for income taxes	**12**	(33)
Cash paid for interest, net of amounts capitalized	**381**	386
Property, plant and equipment non-cash accruals	**34**	65

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2019**	2018
(millions of Canadian dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**77**	17
Restricted cash	**—**	32
Accounts receivable and other *(Notes 6 and 7)*	**1,317**	1,312
Accounts receivable from affiliates *(Note 22)*	**46**	22
Gas inventory *(Note 6)*	**631**	687
Assets held for sale, current *(Note 5)*	**—**	22
	2,071	2,092
Property, plant and equipment, net *(Note 8)*	**15,418**	14,818
Deferred amounts and other assets *(Notes 6, 10, 16, 17 and 18)*	**2,235**	1,931
Intangible assets, net *(Note 9)*	**173**	209
Goodwill	**4,784**	4,784
Assets held for sale, long-term *(Note 5)*	**—**	116
Total assets	**24,681**	23,950
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings *(Note 12)*	**898**	1,025
Accounts payable and other *(Notes 6, 11, 16, 17 and 18)*	**1,369**	1,315
Accounts payable to affiliates *(Notes 15 and 22)*	**113**	55
Current portion of long-term debt *(Note 12)*	**400**	—
Liabilities held for sale, current *(Note 5)*	**—**	44
	2,780	2,439
Long-term debt *(Note 12)*	**7,815**	7,543
Other long-term liabilities *(Notes 6, 15, 16, 18 and 21)*	**1,999**	1,773
Deferred income taxes *(Note 17)*	**1,433**	1,319
Loans from affiliate *(Notes 12 and 22)*	**650**	950
Liabilities held for sale, long-term *(Note 5)*	**—**	33
	14,677	14,057
Shareholders' equity		
Share capital *(Note 13)*		
Common shares *(522 and 291 outstanding at December 31, 2019 and 2018, respectively)*	**3,517**	3,030
Additional paid-in capital	**7,253**	7,253
Deficit	**(720)**	(339)
Accumulated other comprehensive loss *(Notes 14 and 18)*	**(46)**	(51)
	10,004	9,893
Total liabilities and shareholders' equity	**24,681**	23,950

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

(Signed)

Cynthia L. Hansen
Director

(Signed)

David G. Unruh
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS OVERVIEW

Enbridge Gas Inc. (the Company) is a rate-regulated natural gas distribution, storage and transmission utility, serving residential, commercial and industrial customers in Ontario. The Company also served areas in northern New York State through its wholly-owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence Gas), prior to disposition on November 1, 2019 *(Note 5).* The Company is a wholly-owned subsidiary of Enbridge Inc. (Enbridge).

AMALGAMATION

On August 30, 2018, Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas) received approval from the Ontario Energy Board (OEB) for their application to amalgamate on January 1, 2019. The amalgamated entity has continued from this date as the Company. The Company continues to have all of the assets, rights, contracts, liabilities and obligations of each of EGD and Union Gas, including licenses and permits.

Prior to the amalgamation, EGD and Union Gas were both indirect wholly-owned subsidiaries of Enbridge and operated as companies under common control since February 27, 2017, when Enbridge completed a stock-for-stock merger transaction to acquire all outstanding common stock of Spectra Energy Corp (Spectra Energy). As a result of the February 27, 2017 merger, Enbridge and its subsidiaries obtained ownership of Union Gas through its ownership in Spectra Energy.

In accordance with generally accepted accounting principles in the United States of America (U.S. GAAP), the Consolidated Financial Statements reflect EGD as the receiving entity with Union Gas' accounts transferred at Enbridge's historical cost as at February 27, 2017. The carrying values of certain assets and liabilities of Union Gas were adjusted to reflect EGD's accounting policies retrospectively to the transfer date. All intercompany transactions and balances have been eliminated.

2. SIGNIFICANT ACCOUNTING POLICIES

These Consolidated Financial Statements are prepared in accordance with U.S. GAAP. Amounts are stated in Canadian dollars unless otherwise noted.

The Company is permitted to prepare its Consolidated Financial Statements in accordance with U.S. GAAP for purposes of meeting Canadian continuous disclosure requirements under an exemption granted by Canadian securities regulators until the earliest of January 1, 2024, the first day of the Company's financial year that commences if and after the Company ceases to have activities subject to rate regulation, or the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within International Financial Reporting Standards specific to entities with activities subject to rate regulation.

Certain comparative disclosures in the notes to the financial statements have been retrospectively adjusted to conform to the current year's presentation.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the Consolidated Financial Statements. Significant estimates and assumptions used in the preparation of the Consolidated Financial Statements include, but are not limited to: carrying values of regulatory assets and liabilities; unbilled revenues; estimates of revenue; depreciation rates and carrying value of property, plant and equipment; amortization rates and carrying value of intangible assets; measurement of goodwill; fair value of asset retirement obligations (AROs); fair value of financial instruments; provisions for income taxes; assumptions used to measure retirement benefits and OPEB; and commitments and contingencies. Actual results could differ from these estimates.

REGULATION

The utility operations of the Company within Ontario are regulated by the OEB, while the utility operations of St. Lawrence Gas were regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities *(Note 6)*.

As a result of rate regulation accounting, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates and amounts collected from customers in advance of costs being incurred. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation accounting, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. The Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

REVENUE RECOGNITION

Revenues from contracts with customers are generally recognized upon the fulfillment of the performance obligations for the distribution, storage, transportation and sale of natural gas. For distribution and transportation service arrangements where the services are simultaneously received and consumed by the customer, revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise areas. Revenue from storage services are recognized as the storage services are provided.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue under such circumstances is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulator, which follow the accounting guidance found in *ASC 980 - Regulated Operations*.

PUSH-DOWN ACCOUNTING

EGD elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted U.S. GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by EGD. Upon adopting push-down accounting, the historical cost of

EGD's property, plant and equipment and related accounts were adjusted by the remaining unamortized fair value adjustment.

The Company has applied push-down accounting with respect to the accounts of Union Gas from February 27, 2017, the date upon which Enbridge acquired common control of EGD and Union Gas. The carrying values of certain assets and liabilities of Union Gas transferred to EGD have been adjusted to reflect Enbridge's historical cost as at February 27, 2017.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in interest rates and foreign exchange rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges.

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in currency exchange rates related to unregulated storage revenue and changes in interest rates *(Note 15)*. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

The Company recognizes the fair value of derivative instruments on the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments in qualifying hedging relationships are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and accounts for these costs as a deduction from Long-term debt on the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

INCOME TAXES

Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For the Company's regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent taxes can be recovered through rates *(Note 6)*. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Consolidated Statement of Financial Position. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

Prior to its sale, the Company's only foreign operation was St. Lawrence Gas. The functional currency of St. Lawrence Gas was the United States dollar (USD). The effects of translating the financial statements of St. Lawrence Gas to Canadian dollars were included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI). Asset and liability accounts were translated at the exchange rates in effect on the date of the Consolidated Statements of Financial Position, while revenues and expenses were translated at monthly average rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased. The Company combines Cash and cash equivalents and Bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements.

RESTRICTED CASH

Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific agreements, are presented as Restricted cash on the Consolidated Statements of Financial Position. Restricted cash represented funds received from the Green Investment Fund (GIF) program. The Company's use of the funds was limited to eligible expenditures for the purpose of executing the program. The Company managed the GIF program separately from its core regulated activities. There was no earnings impact related to the GIF program.

GAS INVENTORY

Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction as authorized by the Regulators. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the Regulators. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are recorded as an adjustment to accumulated depreciation until the last asset in the pool is disposed of. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily include costs which the Regulators have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; derivative financial instruments; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS
Intangible assets consist primarily of certain software costs and emission allowances. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are generally amortized on a straight line basis over their expected lives, commencing when an asset is available for use.

From January 1, 2017 through July 3, 2018, emission allowances were purchased in order to meet greenhouse gas (GHG) compliance obligations and were recorded at their original cost.

GOODWILL
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. For the purposes of impairment testing, the Company has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. If the quantitative goodwill impairment test is performed, the Company determines the fair value of goodwill and compares those values to the carrying value. If the carrying value exceeds its fair value, goodwill impairment is measured at the amount by which the carrying value exceeds its fair value.

ASSET RETIREMENT OBLIGATIONS
AROs associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset’s useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets, it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

PENSION AND OTHER POSTRETIREMENT BENEFITS
The Company provides pension benefits through defined benefit and defined contribution pension plans and OPEB, including group health care and life insurance benefits, through defined benefit OPEB plans.

Defined benefit pension obligation and net periodic benefit cost are estimated using the projected unit credit method, which incorporates management’s best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. The OPEB benefit obligation and net periodic benefit cost are estimated using the projected unit credit method, where benefits are attributed to years of service, taking into consideration projection of benefit costs.

The Company uses mortality tables issued by the Canadian Institute of Actuaries (revised in 2014) to measure the benefit obligation of its pension plans.

The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans.

Funded pension plan assets are measured at fair value. The expected return on funded pension plan assets is determined using market related values and assumptions on the invested asset mix consistent with the investment policies relating to the plan assets. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period (funded pension plans) and from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount and salary inflation experience.

The excess of the fair value of a plan’s assets over the fair value of a plan’s benefit obligation is recognized as Deferred amounts and other assets in the Company’s Consolidated Statements of Financial Position. The excess of the fair value of a plan’s benefit obligation over the fair value of a plan’s assets is recognized as Accounts payable and other and Other long-term liabilities in the Company’s Consolidated Statements of Financial Position.

Net periodic benefit cost is charged to Earnings and includes:

- Cost of benefits provided in exchange for employee services rendered during the year (current service cost);
- Interest cost of plan obligations;
- Expected return on plan assets (funded pension plans);
- Amortization of prior service costs on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit OPEB plans are presented as a component of AOCI in the Consolidated Statements of Shareholders' Equity. Any unrecognized OPEB-related actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax. Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans, which have been permitted or are expected to be permitted by the Regulators, to be recovered through future rates, are presented as a component of Deferred amounts and other assets in the Company's Consolidated Statements of Financial Position.

The Company also records regulatory adjustments to reflect the difference between certain net periodic benefit costs for accounting purposes and net periodic benefit costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to Earnings and OCI on an accrual basis.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or a liability has been incurred, and the amount of the impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW ACCOUNTING STANDARDS

Cloud Computing Arrangements

Effective January 1, 2019, the Company adopted Accounting Standards Update (ASU) 2018-15 on a prospective basis. The new standard was issued to provide guidance on the accounting for implementation costs incurred in a cloud computing arrangement that is a service contract. The ASU specifies that an entity would apply Accounting Standards Codification (ASC) 350-40, internal-use software, to determine which implementation costs related to a hosting arrangement that is a service contract should be capitalized and which should be expensed. The amendments in the update also require that the capitalized costs be amortized on a straight-line basis generally over the term of the arrangement and presented in the same income statement line as fees paid for the hosting service, in addition to specifying that the capitalized costs must be presented on the same balance sheet line as the prepayment of fees related to the hosting arrangement. The ASU requires similar consistency in classifications from a cash flow statement perspective. The adoption of this ASU did not have a material impact on the Consolidated Financial Statements.

Recognition of Leases

Effective January 1, 2019 the Company adopted ASU 2016-02 Leases (Topic 842) using the modified retrospective approach.

The Company recognizes an arrangement as a lease when a customer in the arrangement has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. The Company recognizes right-of-use (ROU) assets and the related lease liabilities on the statement of financial position for operating lease arrangements with a term of 12 months or longer. The Company does not separate non-lease components from the associated lease components of lessee contracts and accounts for both components as a single lease component. The Company combines lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach as is applied for other long-lived assets, as described in *Note 2 Significant Accounting Policies.*

Lease liabilities and ROU assets require the use of judgment and estimates, which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

In adopting Topic 842, the Company elected the package of practical expedients permitted under the transition guidance. The election to apply the package of practical expedients allows an entity to not apply the new lease standard to the prior year comparative periods in the year of adoption. The application of the package of practical expedients also permits entities not to reassess whether any expired or existing contracts contain leases in accordance with the new guidance, lease classifications, and whether initial direct costs capitalized under current guidance continue to meet the definition of initial direct costs under the new guidance. The Company also elected the practical expedient related to land easements, allowing it to carry forward accounting treatment for land easements on existing agreements that had commenced prior to January 1, 2019.

On January 1, 2019, the Company recorded ROU assets based on corresponding lease liabilities of $52 million. When measuring lease liabilities existing at January 1, 2019, the Company discounted lease payments using the weighted average discount rate of 3.3%. There were no impacts on the Consolidated Statements of Earnings, Comprehensive Income, Shareholder's Equity and Cash Flows.

The following ASUs have been issued, but not yet adopted:

Accounting for Income Taxes
ASU 2019-12 was issued in December 2019 with the intent of simplifying the accounting for income taxes. The accounting update removes certain exceptions to the general principles in ASC 740 as well as provides simplification by clarifying and amending existing guidance. ASU 2019-12 is effective January 1, 2021 and entities are permitted to adopt the standard early. We are currently assessing the impact of the new standard on the Consolidated Financial Statements.

Clarifying Interaction between Collaborative Arrangements and Revenue from Contracts with Customers
ASU 2018-18 was issued in November 2018 to provide clarity on when transactions between entities in a collaborative arrangement should be accounted for under the new revenue standard, ASC 606. In determining whether transactions in collaborative arrangements should be accounted under the revenue standard, the update specifies that entities shall apply unit of account guidance to identify distinct goods or services and whether such goods and services are separately identifiable from other promises in the contract. ASU 2018-18 also precludes entities from presenting transactions with a collaborative partner which are not in scope of the new revenue standard together with revenue from contracts with customers. The accounting update is effective January 1, 2020 and early adoption is permitted. The adoption of ASU 2018-18 is not expected to have a material impact on the Consolidated Financial Statements.

Disclosure Effectiveness
In August 2018, the Financial Accounting Standards Board (FASB) issued two amendments as a part of its disclosure framework project aimed to improve the effectiveness of disclosures in the notes to financial statements.

ASU 2018-14 was issued in August 2018 to improve disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendment modifies ASC 715, Compensation - Retirement Benefits, by adding and removing several disclosure requirements while also clarifying the guidance on current disclosure requirements. ASU 2018-14 is effective January 1, 2021 and entities are permitted to adopt the standard early. The adoption of ASU 2018-14 is not expected to have a material impact on the Consolidated Financial Statements.

ASU 2018-13 was issued to modify the disclosure requirements in ASC 820, Fair Value Measurement. The amendments in ASU 2018-13 eliminate and modify some disclosures, while also adding new disclosures for fair value measurements. This update is effective January 1, 2020, however entities are permitted to early adopt the eliminated or modified disclosures. The adoption of ASU 2018-13 is not expected to have a material impact on the Consolidated Financial Statements.

Accounting for Credit Losses
ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity will recognize as an allowance its estimate of expected credit losses, which the FASB believes will result in more timely recognition of such losses.

Further, ASU 2018-19 was issued in November 2018 to clarify that operating lease receivables should be accounted for under the new leases standard, ASC 842, and are not within the scope of ASC 326, Financial Instruments - Credit Losses. Both accounting updates are effective January 1, 2020.

The Company has performed a detailed evaluation as of December 31, 2019 and does not anticipate the adoption of ASU 2016-13 to have a material impact on the Consolidated Financial Statements.

4. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS

Major Services

December 31,	**2019**	2018
(millions of Canadian dollars)		
Gas commodity and distribution revenue - residential	**2,847**	2,894
Gas commodity and distribution revenue - commercial and industrial	**1,316**	1,385
Storage revenue	**140**	147
Transportation revenue	**716**	843
Other revenue	**65**	46
Total revenue from contracts with customers	**5,084**	5,315
Other	**(9)**	(18)
Total operating revenues	**5,075**	5,297

The Company disaggregates revenue into categories which represent its principal performance obligations because these revenue categories represent the most significant revenue streams, and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Receivables	Contract Liabilities
(millions of Canadian dollars)		
Balance as at January 1, 2019	**589**	**63**
Balance as at December 31, 2019	**613**	**65**
Balance as at January 1, 2018	801	75
Balance as at December 31, 2018	589	63

Receivables represent an unconditional right to consideration where only the passage of time is required before payment of consideration is due and consist of trade accounts receivable, unbilled revenue and other accrued receivable balances.

Contract liabilities represent payments received for performance obligations which have not been fulfilled under the Company's equal billing and budget billing programs. Revenue recognized during the year ended December 31, 2019 included in contract liabilities at the beginning of the period is $63 million (2018 - $75 million). Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2019 were $65 million (2018 - $63 million).

Performance Obligations

	Nature of Performance Obligation
Gas commodity and distribution revenue	• Supply and delivery of natural gas to customers.
Storage and transportation revenue	• Storage and transportation of natural gas on behalf of customers.
Other revenue	• Other billing and service fees.

The Company recognized a reduction of revenue in the current period of $7 million (2018 - $12 million) from performance obligations satisfied in previous periods, primarily resulting from differences in actual and estimated consumption, as discussed below in *Significant Judgments Made in Recognizing Revenue*. The associated reduction in gas commodity and distribution costs was also recognized in the current period.

Payment Terms
Payments from distribution revenue customers are received on a continuous basis based on established billing cycles. The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. Payments from transportation revenue customers are received on a continuous basis based on established billing cycles, or monthly under long-term transportation capacity contracts. Payments from storage customers are received monthly under long-term storage capacity contracts.

Revenue to be Recognized from Unfulfilled Performance Obligations
Total revenue from performance obligations expected to be fulfilled in future periods is $623 million, of which $298 million is expected to be recognized during the year ending December 31, 2020.

The amounts above reflect revenues expected to be recognized in future periods from unfulfilled performance obligations pursuant to contracts with customers for the purchase of natural gas distribution, transportation and storage services. The Company uses the optional exemption available under ASC 606 whereby certain revenues such as flow through costs charged to customers are recognized at the amount for which the Company has the right to invoice its customers. Those revenues are not included in the amounts above. The Company also uses the optional exemption available under ASC 606 whereby revenues from contracts with customers which have an original expected duration of one year or less are excluded from the amounts above. Variable consideration is excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, the Company considers interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. A significant portion of the Company's operations are subject to regulation and accordingly the amounts above only include, where applicable, revenue for which the underlying rate has been approved by regulation. The revenues excluded from the amounts above, as explained, represent a significant portion of the Company's overall revenues and revenues from contracts with customers.

SIGNIFICANT JUDGEMENTS MADE IN RECOGNIZING REVENUE

Revenue Recognition
Revenues from contracts with customers are generally recognized upon the fulfillment of the performance obligations as described above. Distribution and transportation service revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company’s distribution franchise areas.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue under such circumstances is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator, which follow the accounting guidance found in *ASC 980 - Regulated Operations*.

Recognition and Measurement of Revenue

Timing of Revenue Recognition

December 31,	**2019**	2018
(millions of Canadian dollars)		
Revenue from products and services transferred over time[1]	**5,019**	5,246
Revenue from products transferred at a point in time[2]	**65**	69
Total revenue from contracts with customers	**5,084**	5,315

1 Revenue from distribution, transportation and storage services.
2 Primarily from other revenue.

Performance Obligations Satisfied Over Time
For distribution and transportation services arrangements where the services are simultaneously received and consumed by the customer, the Company recognizes revenue over time using an output method based on volumes of commodities delivered.

Revenue from storage services are recognized as the storage services are provided.

Determination of Transaction Prices
Prices for distribution and transportation services and regulated storage services are prescribed by regulation. Fees for unregulated storage services are determined through negotiations with customers based on market rates. Prices for the natural gas commodity are driven by market prices and the Company has a quarterly rate adjustment mechanism in place that allows for rates to reflect changes in natural gas prices, subject to regulatory approval.

5. DISPOSITION

ST. LAWRENCE GAS COMPANY, INC.
In August 2017, the Company entered into an agreement to sell the issued and outstanding shares of its wholly-owned subsidiary, St. Lawrence Gas and classified St. Lawrence Gas as held for sale on the Consolidated Statements of Financial Position. On November 1, 2019, the Company closed the previously announced sale of St. Lawrence Gas for total cash proceeds of approximately $72 million (US $55 million). A loss on disposal of approximately $10 million before tax was included in Other income in the Consolidated Statements of Earnings.

6. REGULATORY MATTERS

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS
The Company is regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act*, (1998), which is part of a package of legislation known as the *Energy Competition Act*, (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario.

The Company records assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities.

RATE APPROVALS

The Company's distribution rates, beginning in 2019, are set under a five-year incentive regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires the Company to share any earnings in excess of 150 basis points over the annual OEB approved return on equity equally with customers.

FINANCIAL STATEMENT EFFECTS

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	**2019**	2018	Consolidated Statements of Financial Position	Recovery/Refund Period Ends
(millions of Canadian dollars)				
Current regulatory assets				
Purchase gas variance[1]	**23**	196	AR	2020
Federal carbon receivables[8]	**145**	—	AR	2020
Other current regulatory assets	**122**	97	AR	2020
Total current regulatory assets	**290**	293		
Long-term regulatory assets				
Deferred income taxes - long-term[2]	**1,266**	1,131	DA	Various
Pension plan receivable[3]	**222**	60	DA	Various
OPEB[4]	**53**	58	DA	Various
Long-term debt[7]	**362**	387	DA	Various
Other long-term regulatory assets	**187**	—	DA	Various
Total long-term regulatory assets	**2,090**	1,636		
Total regulatory assets[5]	**2,380**	1,929		
Current regulatory liabilities				
Purchase gas variance[1]	**41**	—	AP	2020
Other current regulatory liabilities	**176**	135	AP	2020
Total current regulatory liabilities	**217**	135		
Long-term regulatory liabilities				
Future removal and site restoration reserves[6]	**1,424**	1,356	OLTL	Various
Other long-term regulatory liabilities	**47**	24	OLTL	Various
Total long-term regulatory liabilities	**1,471**	1,380		
Total regulatory liabilities[5]	**1,688**	1,515		

AR – Accounts receivable and other
AP – Accounts payable and other
DA – Deferred amounts and other assets
OLTL – Other long-term liabilities

1 *Purchase gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. The Company has been granted OEB approval to refund this balance to, or collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process.*

2 *The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate regulation accounting, this regulatory balance and the related earnings impact would not be recorded.*

3 *The pension plan balance represents the Company's regulatory offset to the pension liability to the extent the amounts are to be collected in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation accounting, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

4 *The OPEB balance represents the Company's right to recover OPEB costs resulting from the adoption of the accrual basis of accounting for OPEB costs upon transition to US GAAP in 2012. Pursuant to the OEB rate order, the amount as at December 31, 2012 is to be collected in rates over a 20-year period that commenced in 2013. In the absence of rate regulation accounting, this regulatory balance and related earnings impact would not be recorded.*

5 *All regulatory assets and liabilities are excluded from rate base unless otherwise noted.*

6 *Future removal and site restoration reserves result from amounts collected from customers by the Company, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment that is recorded in rates. The balance represents the amount that the Company has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation accounting, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

7 *The debt balance represents the Company's regulatory offset to the fair value adjustment to debt pushed down to the Company. The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.*

8 *The federal carbon balance is the difference between actual carbon costs and carbon costs recovered in rates, as well as the Company's administration costs associated with the impacts of the federal carbon program requirements. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation accounting, this regulatory balance and the related earnings impact would not be recorded.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Operating Cost Capitalization

In the absence of rate regulation accounting, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred.

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation accounting, a portion of such operating costs would be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs were capitalized to gas mains in accordance with regulatory approval. At December 31, 2019, the net book value of these costs included in gas mains in Property, plant and equipment, net was $103 million (2018 - $110 million). In the absence of rate regulation accounting, some of these costs would be charged to earnings in the year incurred.

WAMS is the Company's integrated work and asset management solution. At December 31, 2019, the net book value of the asset included in intangible assets was $60 million (2018 - $68 million). In the absence of rate regulation accounting, a portion of the original cost of the asset would have been expensed in the period incurred.

Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. Included in gas inventories at December 31, 2019 is $66 million (2018 - $59 million) related to the Company storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation accounting, these costs would be expensed as incurred and inventory would be recorded at the lower of cost or market value.

Depreciation

In the absence of rate regulation accounting, depreciation rates would not have included a charge for future removal and site restoration costs.

7. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2019**	2018
(millions of Canadian dollars)		
Trade receivables	**581**	548
Unbilled revenues	**314**	270
Gas imbalances[1]	**44**	84
Regulatory assets *(Note 6)*	**290**	293
Rebillables receivable	**88**	110
Other	**38**	45
Allowance for doubtful accounts *(Note 15)*	**(38)**	(38)
	1,317	1,312

[1]The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Consolidated Statements of Financial Position dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

8. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2019**	2018[1]
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas transmission	**2.45%**	**1,505**	1,398
Gas mains, services and other	**2.68%**	**12,114**	11,501
Compressors, meters and other operating equipment	**4.52%**	**2,918**	2,716
Storage	**2.83%**	**919**	891
Land and right-of-way	**1.04%**	**334**	307
Vehicles, office furniture, equipment and other buildings and improvements	**7.35%**	**506**	475
Under construction	**—**	**223**	193
		18,519	17,481
Accumulated depreciation		**(3,490)**	(3,056)
		15,029	14,425
Unregulated property, plant and equipment			
Gas mains, services and other	**6.65%**	**13**	13
Compressors, meters and other operating equipment	**1.30%**	**40**	39
Storage	**3.07%**	**347**	347
Land and right-of-way	**1.83%**	**32**	32
Under construction	**—**	**24**	13
		456	444
Accumulated depreciation		**(67)**	(51)
		389	393
Property, plant and equipment, net		**15,418**	14,818

1 2018 comparative figures were reclassified to conform to the current year's asset classification to reflect the application of push-down accounting.

Depreciation expense, including amounts collected for future removal and site restoration costs, was $558 million for the year ended December 31, 2019 (2018 - $540 million).

Included within depreciation expense is $22 million for the year ended December 31, 2019 (2018 - $22 million) in incremental depreciation resulting from push-down accounting *(Note 2)*.

9. INTANGIBLE ASSETS

December 31,	**2019**	2018[1]
(millions of Canadian dollars)		
Software and Customer Information System (CIS)	**592**	557
Less: Accumulated amortization	**(419)**	(348)
Intangible assets, net	**173**	209

1 2018 comparative figures reflect the application of push-down accounting.

For the year ended December 31, 2019, the weighted average amortization rate for software and CIS was 13.9% (2018 - 12.6%).

Intangible assets include $16 million of work-in-progress as at December 31, 2019 (2018 - $33 million). Total amortization expense for intangible assets was $80 million for the year ended December 31, 2019 (2018 - $68 million). The Company expects aggregate amortization expense for the years ending December 31, 2020 through 2024 of $58 million, $35 million, $18 million, $15 million, and $15 million, respectively.

10. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2019**	2018
(millions of Canadian dollars)		
Regulatory assets *(Note 6)*	**2,090**	1,636
Pension and OPEB assets	**34**	29
Other	**111**	266
	2,235	1,931

11. ACCOUNTS PAYABLE AND OTHER

December 31,	**2019**	2018
(millions of Canadian dollars)		
Trade payables and accrued liabilities	**572**	702
Gas imbalances[1]	**44**	84
Regulatory liabilities *(Note 6)*	**217**	135
Federal carbon program liability	**140**	—
Taxes payable	**114**	74
Other	**282**	320
	1,369	1,315

[1]The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Consolidated Statements of Financial Position dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

12. DEBT

On July 11, 2019, the Company entered into a new trust indenture and filed a $2 billion medium-term notes (MTN) shelf prospectus with Canadian securities regulators. The prospectus is effective for a 25-month period.

December 31,	Weighted Average Interest Rate	Maturity	**2019**	2018
(millions of Canadian dollars)				
Medium-term notes[1]	4.16%	2020-2050	**7,685**	6,985
Debentures	9.14%	2024-2025	**210**	210
Commercial paper and credit facility draws	2.03%	2021	**898**	1,025
Other[2]			**(42)**	(40)
Fair value adjustment from push down accounting *(Note 2)*			**362**	388
Total debt			**9,113**	8,568
Current maturities			**(400)**	—
Short-term borrowings	2.03%		**(898)**	(1,025)
Long-term debt			**7,815**	7,543
Loans from affiliate companies *(Note 22)*			**650**	950

1 The balance pertaining to St. Lawrence Gas amounting to approximately $10 million as at December 31, 2018 was presented as Liabilities held for sale, long term (Note 5) on the Consolidated Statements of Financial Position.
2 Primarily unamortized discounts and debt issuance costs.

On August 9, 2019, the Company issued $400 million of 10-year MTNs and $300 million of 30-year MTNs at an interest rate of 2.37% and 3.01%, respectively, payable semi-annually in arrears. The notes mature on August 9, 2029 and August 9, 2049, respectively.

In September 2018, EGD borrowed $300 million from its parent company, Enbridge through a subordinated promissory note at an interest rate of 3.37%, payable quarterly in arrears. The note was repaid in August 2019.

In October 2018, Union Gas borrowed $650 million from Westcoast Energy Inc., an affiliate under common control, through a subordinated promissory note at an interest rate of 3.65%, payable semi-annually in arrears. This note matures in October 2028.

For the years ending December 31, 2020 through 2024, debentures and medium-term note maturities are $400 million, $375 million, $125 million, $350 million and $300 million, respectively. The Company's debentures and medium-term notes bear interest at fixed rates, and interest obligations for the years ending December 31, 2020 through 2024 are $339 million, $320 million, $306 million, $303 million and $287 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2019**	2018
(millions of Canadian dollars)		
Debentures and term notes	**331**	338
Commercial paper and credit facility draws	**31**	16
Interest on loans from affiliates *(Note 22)*	**31**	34
Other interest and finance costs	**12**	8
Capitalized	**(5)**	(5)
	400	391

The Company's borrowings, whether senior debentures or MTNs, are unsecured.

CREDIT FACILITIES

On February 7, 2019, the Company extended the term out date of its external credit facility to July 24, 2020, with a maturity date of July 24, 2021, and increased the size of total commitments to $2 billion. The Company's credit facility and commercial paper program through Union Gas were terminated. On February 28, 2019, the Company also increased the size of its commercial paper program to $2 billion which is backstopped by committed lines of credit of $2 billion. Issues of commercial paper and revolving borrowings reduce the amount available under the credit facility.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2019.

			December 31, 2019		December 31, 2018
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge Gas Inc.	2021[2]	**2,000**	**898**	**1,102**	1,700
St. Lawrence Gas Company, Inc.[3]		**—**	**—**	**—**	18
Total credit facilities		**2,000**	**898**	**1,102**	1,718

1 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the external credit facility. St. Lawrence Gas draws were presented as Liabilities held for sale, current and long-term on the Consolidated Statements of Financial Position.

2 Maturity date is inclusive of the one year term out option.

3 On November 1, 2019, the Company closed the sale of St. Lawrence Gas (Note 5).

Credit facilities carried a weighted average standby fee of 0.1% on the unused portion and the draws bear interest at market rates.

DEBT COVENANTS

The Company's credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or terminations of the agreements may result if the Company were to default on payment or violate certain covenants. As at December 31, 2019, the Company was in compliance with all debt covenants.

13. SHARE CAPITAL

At December 31, 2019, the authorized share capital of the Company consisted of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

	2019		2018	
December 31,	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of common shares in millions)				
Enbridge Gas Inc.				
Common shares converted from amalgamation	**522**	**3,030**	—	—
Capital contribution	**—**	**800**	—	—
Return of capital	**—**	**(313)**	—	—
Balance at end of year *(Note 22)*	**522**	**3,517**	—	—
Enbridge Gas Distribution Inc.				
Balance at beginning of year	**233**	**2,317**	213	2,417
Common shares converted from amalgamation	**(233)**	**(2,317)**	—	—
Common shares issued	**—**	**—**	20	350
Return of capital	**—**	**—**	—	(450)
Balance at end of year *(Note 22)*	**—**	**—**	233	2,317
Union Gas Limited				
Balance at beginning of year	**58**	**713**	58	657
Common shares converted from amalgamation	**(58)**	**(713)**	—	—
Common shares issued[1]	**—**	**—**	—	57
Return of capital	**—**	**—**	—	(1)
Balance at end of year *(Note 22)*	**—**	**—**	58	713

1 In February 2018 Union Gas Gas issued 621,866 shares for $57 million. Total Union Gas shares outstanding 58,444,516.

The Company is authorized to issue an unlimited number of Class A and Class B common shares. On January 1, 2019, the Company issued to Enbridge Energy Distribution Inc. (EEDI), which wholly-owned EGD and owned 1% of Union Gas, 281,881,334 Class A common shares in exchange for 232,749,988 EGD common shares and 621,866 Union Gas Class A common shares. Great Lakes Basin Energy L.P. (GLBE), which owned 99% of Union Gas, was issued 240,020,243 Class B common shares of the Company in exchange for 57,822,650 Union Gas common shares. Both classes of common shares of the Company are identical in every respect. Dividends cannot be paid to one class without paying dividends on the other.

On February 1, 2019, the stated capital of Class B common shares held by GLBE was reduced by approximately $1 million as part of a return of capital transaction, which had no impact on total shares outstanding.

On November 15, 2019, the stated capital of Class A common shares held by EEDI and Class B common shares held by GLBE were reduced by approximately $169 million and $143 million, respectively, as part of a return of capital transaction, which had no impact on total shares outstanding.

On November 27, 2019, the Company received capital contributions of $432 million and $368 million, respectively, from EEDI and GLBE, which had no impact on total shares outstanding.

14. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Changes in AOCI for the years ended December 31, 2019 and 2018 are as follows:

	2019			
	Cash Flow Hedges	Cumulative Translation Adjustment	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)				
Balance at January 1, 2019	**(9)**	**5**	**(47)**	**(51)**
Other comprehensive income/(loss) retained in AOCI	**(50)**	**(2)**	**58**	**6**
Other comprehensive (income)/loss reclassified to earnings	**5**	**(3)**	**—**	**2**
	(54)	**—**	**11**	**(43)**
Tax Impact				
Income tax on amounts retained in AOCI	**13**	**—**	**(15)**	**(2)**
Income tax on amounts reclassified to earnings	**(1)**	**—**	**—**	**(1)**
	12	**—**	**(15)**	**(3)**
Balance at December 31, 2019	**(42)**	**—**	**(4)**	**(46)**

	2018			
	Cash Flow Hedges	Cumulative Translation Adjustment	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)				
Balance at January 1, 2018	(8)	1	(32)	(39)
Other comprehensive income/(loss) retained in AOCI	(6)	4	(20)	(22)
Other comprehensive loss reclassified to earnings	4	—	—	4
	(10)	5	(52)	(57)
Tax Impact				
Income tax on amounts retained in AOCI	2	—	5	7
Income tax on amounts reclassified to earnings	(1)	—	—	(1)
	1	—	5	6
Balance at December 31, 2018	(9)	5	(47)	(51)

OCI for the twelve months ended December 31, 2019 was increased by an adjustment of $74 million in respect of the Company applying rate regulated accounting to record a regulatory offset to certain pension liabilities of the Company. An offsetting amount of $19 million was also recorded for the related tax impact in OCI.

15. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and OCI are subject to movements in natural gas prices, foreign exchange rates and interest rates (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customers.

Foreign Exchange Risk
Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. The Company generates certain revenues and held a subsidiary that was denominated in USD. As a result, the Company's earnings, cash flows, and OCI are exposed to fluctuations resulting from USD exchange rate variability.

The Company implemented a policy to hedge a portion of USD denominated unregulated storage revenue exposures. Qualifying derivative instruments are used to hedge anticipated USD denominated revenues and to manage variability in cash flows.

A portion of the Company's purchases of natural gas are denominated in USD and as a result there is exposure to fluctuations in the exchange rate of the USD against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to customers, therefore the Company has no net exposure to movements in the foreign exchange rate on natural gas purchases.

The Company did not have any outstanding derivative instruments relating to net investment hedges as at December 31, 2019 and December 31, 2018.

Interest Rate Risk
The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 2.3%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.7%.

The Company's portfolio mix of fixed and variable rate debt instruments is monitored by its ultimate parent company, Enbridge.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the financial statement line item in the Consolidated Statements of Financial Position and carrying value of the Company's derivative instruments.

The Company generally has a common practice of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2019	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable to affiliates					
Interest rate contracts	**(9)**	**—**	**(9)**	**—**	**(9)**
	(9)	**—**	**(9)**	**—**	**(9)**
Other long-term liabilities					
Foreign exchange contracts	**—**	**—**	**—**	**—**	**—**
Interest rate contracts	**(13)**	**—**	**(13)**	**—**	**(13)**
	(13)	**—**	**(13)**	**—**	**(13)**
Total net derivative asset/(liability)					
Foreign exchange contracts	**—**	**—**	**—**	**—**	**—**
Interest rate contracts	**(22)**	**—**	**(22)**	**—**	**(22)**
	(22)	**—**	**(22)**	**—**	**(22)**

December 31, 2018	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable to affiliates					
Interest rate contracts	(2)	—	(2)	—	(2)
	(2)	—	(2)	—	(2)
Other long-term liabilities					
Foreign exchange contracts	(1)	—	(1)	—	(1)
Interest rate contracts	(3)	—	(3)	—	(3)
	(4)	—	(4)	—	(4)
Total net derivative asset/(liability)					
Foreign exchange contracts	(1)	—	(1)	—	(1)
Interest rate contracts	(5)	—	(5)	—	(5)
	(6)	—	(6)	—	(6)

The following table summarizes the maturity and notional principal or quantity outstanding related to the Company's derivative instruments.

December 31, 2019	2020	2021	2022	2023	2024	Thereafter
Foreign exchange contracts - United States dollar forwards - sell *(millions of USD)*	**3**	**3**	**1**	**—**	**—**	**—**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**539**	**387**	**18**	**—**	**—**	**—**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**180**	**275**	**—**	**—**	**—**	**—**

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and comprehensive income, before the effect of income taxes.

Year ended December 31,	2019	2018
(millions of Canadian dollars)		
Amount of unrealized loss recognized in OCI cash flow hedges		
Interest rate contracts	**(50)**	(5)
Foreign exchange contracts	**—**	(1)
	(50)	(6)
Amount of loss reclassified from AOCI to earnings		
Interest rate contracts[1]	**6**	(4)
Foreign exchange contracts	**(1)**	—
	5	(4)

1 Reported within Interest expense in the Consolidated Statements of Earnings.

The Company estimates a loss of $2 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on interest and foreign exchange rates in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 24 months as at December 31, 2019.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under committed credit facilities and long-term debt, which includes debentures and MTNs and, if necessary, additional liquidity is available through intercompany transactions with its ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable the Company to fund all anticipated requirements. The Company maintains a current MTN shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. The Company also maintains committed credit facilities with a diversified group of banks and institutions. The Company is in compliance with all the terms and conditions of its committed credit facilities as at December 31, 2019. As a result, all credit facilities are available to the Company and the banks are obligated to fund the Company under the terms of the facilities.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which generally require payment in full within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts, which totaled $38 million at December 31, 2019 (December 31, 2018 - $38 million).

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate.

Entering into derivative financial instruments may also result in exposure to credit risk. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. As at December 31, 2019 the Company does not have any significant group credit concentrations and maximum credit exposure, with respect to derivative instruments, in any counterparty segments.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company categorizes its derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company does not have any derivative instruments classified as Level 1.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using

Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps for which observable inputs can be obtained.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support a Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2019, the Company had Level 2 derivative assets with fair value of $nil (2018 - $nil million) and Level 2 derivative liabilities with fair value of $22 million (2018 - $6 million). The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers between levels as at December 31, 2019 or December 31, 2018.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS
The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in net income, unless actively quoted market prices are not available for fair value measurement in which case these investments are recorded at the fair value measurement alternative.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2019, the Company's long-term debt, including the current portion had a carrying value of $7,895 million (2018 - $7,195 million) before debt issue costs and a fair value of $9,182 million (2018 - $7,855 million).

The fair value of other financial assets and liabilities other than derivative instruments and long-term debt approximate their cost due to the short period to maturity.

16. LEASES

The Company incurs operating lease payments related to natural gas storage and real estate. The Company's operating lease agreements have remaining lease terms of 3 months to 10 years, some of which include options to terminate at our discretion.

For the year ended December 31, 2019, the Company incurred operating lease expenses of $7 million. Operating lease expenses are reported within Operating and administrative expenses in the Consolidated Statements of Earnings.

For the year ended December 31, 2019, operating lease payments to settle lease liabilities were $7 million. Operating lease payments are reported within Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Consolidated Statements of Financial Position Information

December 31,	**2019**	2018
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases		
Operating lease right-of-use assets, net[1]	**46**	52
Operating lease liabilities - current[2]	**6**	6
Operating lease liabilities - long-term[3]	**40**	46
Total operating lease liabilities	**46**	52
Weighted average remaining lease term		
Operating leases	**9 years**	9 years
Weighted average discount rate		
Operating leases	**3.3%**	3.3%

1 Right-of-use assets are reported within Deferred amounts and other assets in the Consolidated Statements of Financial Position.
2 Current lease liabilities are reported within Accounts payable and other in the Consolidated Statements of Financial Position.
3 Long-term lease liabilities are reported within Other long-term liabilities in the Consolidated Statements of Financial Position.

As at December 31, 2019 the Company's operating lease liabilities are expected to mature as follows:

	Operating leases
(millions of Canadian dollars)	
2020	**7**
2021	**7**
2022	**6**
2023	**5**
2024	**5**
Thereafter	**22**
Total undiscounted lease payments	**52**
Less imputed interest	**(6)**
Total operating lease liabilities	**46**

17. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2019**	2018
(millions of Canadian dollars)		
Earnings before income taxes	**614**	625
Federal statutory income tax rate	**15.0%**	15.0%
Federal income taxes at statutory rate	**92**	94
Increase/(decrease) resulting from:		
Provincial and state income taxes	**29**	(4)
Effects of rate regulated accounting[1]	**(52)**	(56)
Non-taxable intercompany distributions[1]	**—**	(9)
Part VI.1 tax, net of federal Part I tax deduction[1]	**—**	31
Non-taxable portion of sale of investment to unrelated party *(Note 5)*	**(1)**	—
Investment in foreign subsidiaries	**—**	1
Other[2]	**(10)**	—
Income tax expense	**58**	57
Effective income tax rate	**9.4%**	9.1%

1 The provincial tax component of these items is included in "Provincial and state income taxes" above.

2 Included in "Other" are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals and entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2019**	2018
(millions of Canadian dollars)		
Earnings before income taxes		
Canada	**638**	620
United States	**(24)**	5
	614	625
Current income taxes		
Canada	**85**	88
United States	**4**	—
	89	88
Deferred income taxes		
Canada	**(25)**	(32)
United States	**(6)**	1
	(31)	(31)
Income tax expense	**58**	57

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2019**	2018
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**1,497**	1,395
Regulatory assets	**335**	300
Deferrals	**17**	20
Retirement and post-retirement benefits	**8**	—
Other	**1**	10
Total deferred income tax liabilities	**1,858**	1,725
Deferred income tax assets		
Future removal and site restoration reserves	**373**	364
Minimum tax credits	**30**	24
Retirement and post-retirement benefits	**—**	12
Financial derivatives	**15**	3
Other	**7**	3
Total deferred income tax assets	**425**	406
Net deferred income tax liabilities	**1,433**	1,319

The Company and its subsidiaries are subject to taxation in Canada and the United States. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario). The Company is open to examination by Canadian tax authorities for the 2012 to 2019 tax years. The Company is currently under examination for income tax matters in Canada for the 2015 to 2017 tax years.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2019**	2018
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**39**	45
Gross increases for tax positions of current year	**3**	3
Gross decreases for tax positions of prior years	**(1)**	(6)
Settlements	**—**	(1)
Lapses of statute of limitations	**(2)**	(2)
Unrecognized tax benefits at end of year	**39**	39

The unrecognized tax benefits as at December 31, 2019, if recognized, would affect the Company's effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its Consolidated Financial Statements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the years ended December 31, 2019 and 2018 included $nil recoveries of interest and penalties. As of December 31, 2019 and 2018, interest and penalties of $1 million and $1 million, respectively, have been accrued.

18. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS
The Company provides pension benefits, covering substantially all employees, through contributory and non-contributory registered defined benefit and defined contribution pension plans. The Company also provides non-registered pension benefits for certain employees through supplemental non-contributory, defined benefit pension plans.

Defined Benefit Pension Plan Benefits
Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. The Company's contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits
Company contributions are based on each plan participant's current eligible remuneration. Company contributions for some defined contribution pension plans are also based on age and years of service. Defined contribution pension benefit costs to the Company are equal to the amount of contributions required to be made by the Company.

OTHER POSTRETIREMENT BENEFIT PLANS
The Company provides non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees, through unfunded defined benefit OPEB plans.

BENEFIT OBLIGATIONS, PLAN ASSETS AND FUNDED STATUS

The following table details the changes in the benefit obligation, the fair value of plan assets and the recorded assets or liabilities for the Company's defined benefit pension and OPEB plans:

	Pension		OPEB	
December 31,	**2019**	2018	**2019**	2018
(millions of Canadian dollars)				
Change in benefit obligation				
Benefit obligation at beginning of year	**2,080**	2,115	**153**	175
Service cost	**63**	58	**2**	3
Interest cost	**72**	68	**5**	6
Participant contributions	**14**	9	**—**	—
Actuarial (gain)/loss	**210**	(73)	**15**	(25)
Benefits paid	**(108)**	(97)	**(5)**	(7)
Other	**—**	—	**—**	1
Benefit obligation at end of year[1]	**2,331**	2,080	**170**	153
Change in plan assets				
Fair value of plan assets at beginning of year	**1,923**	1,991	**—**	—
Actual return/(loss) on plan assets	**237**	(15)	**—**	—
Employer contributions	**42**	36	**5**	7
Participant contributions	**14**	9	**—**	—
Benefits paid	**(108)**	(97)	**(5)**	(7)
Other	**—**	(1)	**—**	—
Fair value of plan assets at end of year	**2,108**	1,923	**—**	—
Underfunded status at end of year	**(223)**	(157)	**(170)**	(153)
Presented as follows:				
Deferred amounts and other assets *(Note 10)*	**34**	29	**—**	—
Accounts payable and other	**(2)**	(4)	**(7)**	(7)
Other long-term liabilities *(Note 21)*	**(255)**	(182)	**(163)**	(146)
	(223)	(157)	**(170)**	(153)

1 For pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligations is the accumulated postretirement benefit obligation. The accumulated benefit obligation for the Company's pension plans was $2.2 billion and $1.9 billion as at December 31, 2019 and 2018, respectively.

Certain of the Company's pension plans have an accumulated benefit obligation in excess of the fair value of plan assets. For these plans, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets were as follows:

December 31,	**2019**	2018
(millions of Canadian dollars)		
Projected benefit obligation	**685**	595
Accumulated benefit obligation	**611**	537
Fair value of plan assets	**529**	465

AMOUNT RECOGNIZED IN ACCUMULATED OTHER COMPREHENSIVE INCOME

The amount of pre-tax AOCI relating to the Company's pension and OPEB plans are as follows:

	Pension		OPEB	
December 31,	**2019**[1]	2018	**2019**	2018
(millions of Canadian dollars)				
Net actuarial (gain)/loss	**—**	74	**5**	(11)
Total amount recognized in AOCI	**—**	74	**5**	(11)

1 Pension net actuarial loss reflects a reduction of $74 million resulting from the application of rate regulated accounting and recognizing an offsetting long-term regulatory asset for net actuarial loss relating to the Company's pension plans (Note 14).

NET PERIODIC BENEFIT COST AND OTHER AMOUNTS RECOGNIZED IN COMPREHENSIVE INCOME

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to the Company's pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2019**	2018	**2019**	2018
(millions of Canadian dollars)				
Service cost	**63**	58	**2**	3
Interest cost	**72**	68	**5**	6
Expected return on plan assets	**(129)**	(130)	**—**	(1)
Amortization of net actuarial loss[1]	**16**	14	**—**	—
Net periodic benefit cost	**22**	10	**7**	8
Defined contribution benefit cost	**2**	6	**—**	—
Net pension and OPEB cost recognized in Earnings	**24**	16	**7**	8
Amount recognized in OCI:				
Adjustment for rate-regulated accounting *(Note 14)*	**(74)**	—	**—**	—
Net actuarial (gain)/loss arising during the year	**—**	44	**16**	(24)
Total amount recognized in OCI	**(74)**	44	**16**	(24)
Total amount recognized in Comprehensive income	**(50)**	60	**23**	(16)

1 *Reflects amortization of net actuarial loss arising from pension plans that are recognized as long-term regulatory assets* (Note 6).

The Company estimates that approximately $nil related to the pension plans and $1 million related to the OPEB plans as at December 31, 2019 will be reclassified from AOCI into Earnings in the next 12 months.

ACTUARIAL ASSUMPTIONS

The weighted average assumptions made in the measurement of the benefit obligation and net periodic benefit cost of the Company's defined benefit pension and OPEB plans are as follows:

	Pension		OPEB	
	2019	2018	**2019**	2018
Benefit obligation				
Discount rate	**3.1%**	3.8%	**3.1%**	3.8%
Rate of salary increase	**3.2%**	3.1%	**3.3%**	3.3%
Net periodic benefit cost				
Discount rate	**3.8%**	3.7%	**3.8%**	3.7%
Expected rate of return on plan assets	**6.8%**	6.5%	**N/A**	N/A
Rate of salary increase	**3.2%**	3.1%	**3.3%**	3.2%

ASSUMED HEALTH CARE COST TREND RATES

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	2019	2018
Health care cost trend rate assumed for next year	**4.0%**	4.0%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0%**	4.0%

A 1% change in the assumed health care cost trend rate would have the following effects for the year ended and as at December 31, 2019:

	1% Increase	1% Decrease
(millions of Canadian dollars)		
Total service and interest costs	**—**	**—**
Accumulated postretirement benefit obligation	**12**	**(10)**

PLAN ASSETS

The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the Company's operating environment and financial situation and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

Asset Category	Target Allocation	December 31, 2019	2018
Equity securities	**40.8%**	**45.7%**	45.5%
Fixed income securities	**35.8%**	**33.7%**	39.5%
Alternatives[1]	**23.4%**	**20.6%**	15.0%

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

The following table summarizes the fair value of the plan assets for the Company's pension plans recorded at each fair value hierarchy level.

	2019				2018			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Cash and cash equivalents	**53**	**—**	**—**	**53**	74	—	—	74
Equity securities								
Canada	**92**	**112**	**—**	**204**	122	200	—	322
Global	**—**	**760**	**—**	**760**	—	554	—	554
Fixed income securities								
Government	**117**	**272**	**—**	**389**	124	280	—	404
Corporate	**—**	**268**	**—**	**268**	—	281	—	281
Alternatives[4]	**—**	**—**	**427**	**427**	—	—	298	298
Forward currency contracts	**—**	**7**	**—**	**7**	—	(10)	—	(10)
Total pension plan assets at fair value	**262**	**1,419**	**427**	**2,108**	320	1,305	298	1,923

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2019**	2018
(millions of Canadian dollars)		
Balance at beginning of year	**298**	178
Unrealized and realized gains	**9**	39
Purchases and settlements, net	**120**	81
Balance at end of year	**427**	298

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2020	2021	2022	2023	2024	2025-2029
(millions of Canadian dollars)						
Pension	104	107	110	112	115	610
OPEB	7	7	7	8	8	40

EXPECTED EMPLOYER CONTRIBUTIONS

In 2020, the Company expects to contribute approximately $38 million and $7 million to the pension and OPEB plans, respectively.

19. SEVERANCE COSTS

As at December 31, 2018, the Company had $18 million in accrued severance costs included in Accounts payable and other related to termination benefits to employees from the amalgamation of EGD and Union Gas. For the twelve months ended December 31, 2019, $39 million of additional severance costs are included in Operating and administrative expense with $36 million paid during the year. The remaining $21 million will be paid primarily during 2020.

20. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2019**	2018
(millions of Canadian dollars)		
Accounts receivable and other	**(17)**	238
Accounts receivable from affiliates	**(24)**	25
Regulatory assets *(Note 6)*	**29**	(59)
Gas inventory	**48**	(54)
Deferred amounts and other assets	**(2)**	24
Accounts payable and other	**(45)**	36
Accounts payable to affiliates	**18**	(29)
Regulatory liabilities *(Note 6)*	**105**	53
Other long-term liabilities	**(8)**	(8)
Cap and trade compliance liability	**—**	387
Assets held for sale	**12**	(12)
	116	601

21. OTHER LONG-TERM LIABILITIES

December 31,	**2019**	2018
(millions of Canadian dollars)		
Regulatory liabilities *(Note 6)*	**1,471**	1,380
Pension and OPEB liabilities	**418**	328
Other	**110**	65
	1,999	1,773

22. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The Company's transactions with related parties are as follows:

Year ended December 31,	**2019**	2018
(millions of Canadian dollars)		
Enbridge Energy Distribution Inc.		
Common share dividends declared	**506**	542
Capital contribution	**432**	—
Return of capital	**169**	—
Great Lakes Basin Energy L.P.		
Common share dividends declared	**431**	223
Capital contribution	**368**	—
Return of capital	**144**	—
IPL System Inc.		
Dividend income	**—**	60
Interest expense *(Note 12)*	**—**	26
Enbridge		
Charges for centralized services	**99**	72
Part VI.1 tax reimbursement	**—**	3
Transfer of income tax installments	**48**	—
Repayment of note payable	**300**	—
Interest expense *(Note 12)*	**6**	3
Interest income	**13**	—
Enbridge (U.S.) Inc.		
Repayment of note payable	**32**	—
Interest expense *(Note 12)*	**1**	—
Westcoast Energy Inc.		
Interest expense *(Note 12)*	**24**	5
Tidal Energy Marketing Inc.		
Purchase of natural gas	**38**	88
Revenue from optimization services	**1**	4
Revenue from storage and transportation services	**10**	8
Tidal Energy Marketing (U.S.) LLC		
Purchase of natural gas	**37**	68
Gazifère Inc.		
Revenue from wholesale service, including gas sales	**30**	30
Énergir L.P.		
Revenue from storage and transportation services	**10**	—
Vector Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	**19**	26
Nexus Gas Transmission (U.S.)		
Purchase of gas transportation services	**114**	19
Other related entities		
Purchase of natural gas, storage and transportation services	**8**	11
Operating lease payments for natural gas storage assets *(Note 16)*	**6**	—
Revenue from storage and transportation services	**2**	—

The Company had related party balances as follows:

December 31,	**2019**	2018
(millions of Canadian dollars)		
Common share ownership from parent company		
Enbridge Energy Distribution Inc.	**2,636**	2,373
Great Lakes Basin Energy L.P.	**881**	657
Note payable to affiliate company		
Westcoast Energy Inc.	**650**	650
Enbridge	**—**	300
Enbridge (U.S.) Inc.	**—**	33
Right-of-use asset, net from affiliate company		
Sarnia Airport Storage Pool Limited Partnership	**42**	—
Operating lease liability to affiliate company - long-term		
Sarnia Airport Storage Pool Limited Partnership	**38**	—
Derivative instruments to affiliate company		
Enbridge *(Note 15)*	**13**	4
Other accounts receivable/(payable)		
Other related entities, net	**(67)**	(33)

Financing Transactions
In September 2018, EGD borrowed $300 million from its parent company, Enbridge through a subordinated promissory note at an interest rate of 3.37% payable quarterly in arrears. The note was repaid in August 2019.

In October 2018, Union Gas borrowed $650 million from Westcoast Energy Inc., an affiliate under common control, through a subordinated promissory note at an interest rate of 3.65% payable semi-annually in arrears. This note matures in October 2028.

On February 1, 2019, the stated capital of Class B common shares held by GLBE was reduced by approximately $1 million as part of a return of capital transaction, which had no impact on total shares outstanding.

In October 2019, St. Lawrence Gas repaid the balance and accrued interest on the note payable to Enbridge (U.S.) Inc.

On November 15, 2019, the stated capital of Class A common shares held by EEDI and Class B common shares held by GLBE were reduced by approximately $169 million and $143 million, respectively, as part of a return of capital transaction, which had no impact on total shares outstanding.

On November 27, 2019, the Company received capital contributions of $432 million and $368 million, respectively, from EEDI and GLBE, which had no impact on total shares outstanding.

Centralized Services
Enbridge performs centralized corporate functions for the Company, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. The Company reimburses Enbridge for the expenses to provide these services based on the cost of actual services provided or using various allocation methodologies.

Natural Gas Purchases
The Company contracted for the purchase of natural gas from various affiliates, including Tidal Energy Marketing Inc., and Tidal Energy Marketing (U.S.) LLC., at prevailing market prices under normal trade terms. Contractual obligations under the related party contracts are 2020 through 2021 - $15 million, 2022 through 2023 - $nil million, and thereafter - $nil.

Wholesale Service
These gas procurement and transportation services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Storage and Transportation Services
The Company contracted for natural gas transportation services from various affiliates, including Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian) and NEXUS Gas Transmission (U.S.) LLC. Contractual obligations under the related party contracts are 2020 through 2021 - $372 million, 2022 through 2023 - $246 million and thereafter - $1,087 million.

Other Transactions
The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides administrative and other services to certain related entities under common control and records recoveries from these affiliates. The Company recovers the expenses to provide these services based on the cost of actual services provided or using various allocation methodologies. Cost recoveries are recorded as a reduction to Operating and administrative expense in the Consolidated Statements of Earnings.

23. GUARANTEES

In the normal course of conducting business, the Company issues financial guarantees to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Consolidated Statements of Financial Position. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments. While these agreements may specify a maximum potential exposure, or a specified duration, there are circumstances where the amount and duration are unlimited. The guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

24. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

At December 31, 2019, the Company had commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Right-of-way commitments[1]	585	10	10	10	10	10	535
Purchase of services, pipe and other materials, including transportation[2,3]	6,152	1,290	894	598	457	414	2,499
	6,737	1,300	904	608	467	424	3,034

1 Included in these amounts are right-of-way payments, estimated to be approximately $10 million per year, related to cancellable gas storage payments that are reasonably likely to occur over the remaining life of all storage reservoirs.

2 Includes capital and operating commitments.

3 Includes firm capacity payments that provide the Company with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software and consulting or advisory services; customer care services; and contractual obligations for engineering, procurement and construction costs for pipeline projects.

The Company and certain affiliates, in aggregate, have access to $495 million of letters of credit that they can issue. The total outstanding letters of credit that related to the Company as at December 31, 2019 was $14 million.

ENVIRONMENTAL

The Company is subject to various federal, provincial and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on the Company.

Environmental risk is inherent to natural gas pipeline operations, and the Company is, at times, subject to environmental remediation at various contaminated sites. The Company manages this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that the Company is unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, the Company will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of the Company.

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation, isolation, and containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. From 2006 to 2018, the OEB approved the establishment of deferral accounts to record the costs of investigating, defending and dealing with ongoing MGP-related claims. The Company expects that if it is found it must contribute to any remediation costs, either as a result of a lawsuit or government order, it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company’s financial position.

Hamilton Contaminated Site

In April 2016, the Ontario Ministry of the Environment, Conservation and Parks (MECP), formerly the Ministry of the Environment and Climate Change issued a Director’s Order (Order) naming the Company, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of the Company in Hamilton. In May 2016, the Company appealed the Order, and in June 2016, the Environmental Review Tribunal (Tribunal), on consent of the MECP’s Director, stayed the application of parts of the Order. The Tribunal has extended the stay of the Order several times, which has allowed the owner of the property, with the cooperation of the adjacent owners, to prepare a plan of action, including discussions with the MECP and other neighbours. The Company continues to monitor the matter, and to cooperate with the owner of the source property, the MECP and other adjacent owners. The risk of material environmental liability is unknown at this time.

TAX MATTERS

The Company maintains tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATION

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's financial position or results of operations.

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Please see Exhibit I.1.8-STAFF-14 Attachment 2.xlsx on the OEB's RDS.

ENBRIDGE GAS INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2022

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE GAS INC.

Financial Reporting
Management of Enbridge Gas Inc. (the Company) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors is responsible for all aspects related to governance of the Company. The Company does not have an Audit Committee, having received an exemption from such requirement.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with US GAAP and to provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, have conducted an audit of the consolidated financial statements of the Company in accordance with Canadian generally accepted auditing standards and have issued an unqualified audit report, which is accompanying the consolidated financial statements.

/s/ Michele E. Harradence	**/s/ Tanya M. Ferguson**
Michele E. Harradence	Tanya M. Ferguson
President	Vice President, Finance

February 10, 2023

Independent auditor's report

To the Shareholders of Enbridge Gas Inc.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Inc. and its subsidiaries (together, the Company) as at December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America (US GAAP).

What we have audited

The Company's consolidated financial statements comprise:

- the consolidated statements of earnings for the years ended December 31, 2022 and 2021;
- the consolidated statements of comprehensive income for the years ended December 31, 2022 and 2021;
- the consolidated statements of changes in equity for the years ended December 31, 2022 and 2021;
- the consolidated statements of cash flows for the years ended December 31, 2022 and 2021;
- the consolidated statements of financial position as at December 31, 2022 and 2021; and
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Ontario
February 10, 2023

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Operating revenues		
Gas commodity and distribution	**5,613**	3,996
Storage, transportation and other	**995**	897
Total operating revenues *(Note 4)*	**6,608**	4,893
Operating expenses		
Gas commodity and distribution costs	**3,679**	2,146
Operating and administrative	**1,227**	1,105
Depreciation and amortization	**690**	677
Total operating expenses	**5,596**	3,928
Operating income	**1,012**	965
Other income	**79**	43
Interest expense, net *(Note 10)*	**(423)**	(394)
Earnings before income taxes	**668**	614
Income tax expense *(Note 15)*	**(69)**	(63)
Earnings	**599**	551

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Earnings	**599**	551
Other comprehensive income, net of tax *(Note 12)*		
Change in unrealized gain on cash flow hedges	**68**	21
Reclassification to earnings of loss on cash flow hedges	**7**	12
Actuarial gain on other postretirement benefits (OPEB)	**29**	22
Reclassification to earnings of OPEB amounts	**(1)**	—
Other comprehensive income, net of tax	**103**	55
Comprehensive income	**702**	606

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Common shares *(Note 11)*		
Balance at beginning of year	**3,442**	3,517
Capital contribution	**800**	975
Return of capital	**(583)**	(1,050)
Balance at end of year	**3,659**	3,442
Additional paid-in capital		
Balance at beginning and end of year	**7,253**	7,253
Retained earnings/(deficit)		
Balance at beginning of year	**(324)**	(675)
Earnings	**599**	551
Common share dividends declared	**(104)**	(200)
Balance at end of year	**171**	(324)
Accumulated other comprehensive income/(loss) *(Note 12)*		
Balance at beginning of year	**(23)**	(78)
Other comprehensive income, net of tax	**103**	55
Balance at end of year	**80**	(23)
Total equity	**11,163**	10,348

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Operating activities		
Earnings	**599**	551
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**690**	677
Deferred income tax recovery *(Note 15)*	**(15)**	(15)
Net defined pension and OPEB costs	**(56)**	(24)
Expected credit loss	**20**	14
Other	**11**	10
Changes in operating assets and liabilities *(Note 17)*	**(1,171)**	(473)
Net cash provided by operating activities	**78**	740
Investing activities		
Capital expenditures	**(1,482)**	(1,308)
Additions to intangible assets	**(39)**	(72)
Proceeds from disposition	**12**	—
Net cash used in investing activities	**(1,509)**	(1,380)
Financing activities		
Net change in short-term borrowings	**481**	394
Demand loan from affiliate *(Note 18)*	**318**	—
Term note issuances, net of issue costs	**645**	896
Term note repayments *(Note 10)*	**(125)**	(375)
Common share dividends	**(104)**	(200)
Return of capital	**(583)**	(1,050)
Capital contribution received	**800**	975
Net cash provided by financing activities	**1,432**	640
Net change in cash	**1**	—
Cash at beginning of year	**9**	9
Cash at end of year	**10**	9
Supplementary cash flow information		
Cash paid/(received) for income taxes	**1**	(5)
Cash paid for interest, net of amounts capitalized	**400**	374
Property, plant and equipment and intangibles non-cash accruals	**80**	75

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2022**	2021
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash	**10**	9
Accounts receivable and other *(Note 6)*	**2,346**	1,228
Accounts receivable from affiliates	**191**	156
Gas inventory	**1,424**	897
	3,971	2,290
Property, plant and equipment, net *(Note 7)*	**17,601**	16,662
Intangible assets, net *(Note 8)*	**175**	177
Deferred amounts and other assets	**2,996**	2,677
Goodwill	**4,784**	4,784
Total assets	**29,527**	26,590
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 10)*	**1,996**	1,515
Accounts payable and other *(Note 9)*	**1,864**	1,458
Accounts payable to affiliates	**195**	113
Current portion of long-term debt *(Note 10)*	**352**	126
Demand loan from affiliate *(Note 18)*	**318**	—
	4,725	3,212
Long-term debt *(Note 10)*	**9,625**	9,352
Other long-term liabilities	**2,160**	2,012
Deferred income taxes *(Note 15)*	**1,854**	1,666
	18,364	16,242
Commitments and contingencies *(Note 19)*		
Equity		
Share capital *(Note 11)*		
Common shares *(522 outstanding at December 31, 2022 and 2021)*	**3,659**	3,442
Additional paid-in capital	**7,253**	7,253
Retained earnings/(deficit)	**171**	(324)
Accumulated other comprehensive income/(loss) *(Note 12)*	**80**	(23)
	11,163	10,348
Total liabilities and equity	**29,527**	26,590

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

/s/ Michele E. Harradence
Michele E. Harradence
Director

/s/ William T. Yardley
William T. Yardley
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS OVERVIEW

The terms "we", "our", "us" and "Enbridge Gas" as used in these financial statements refer collectively to Enbridge Gas Inc. and its subsidiaries unless the context suggests otherwise. Enbridge Gas is a wholly-owned indirect subsidiary of Enbridge Inc. (Enbridge). Enbridge provides administrative and general support services to us.

Enbridge Gas is a rate-regulated natural gas distribution utility with storage and transmission services, which serves residential, commercial and industrial customers throughout Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (US GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

We are permitted to prepare our consolidated financial statements in accordance with US GAAP for purposes of meeting Canadian continuous disclosure requirements under an exemption granted by Canadian securities regulators until the earliest of January 1, 2027, the first day of our financial year that commences if and after we cease to have activities subject to rate regulation, or the effective date prescribed by the International Accounting Standards Board for the application of a Mandatory Rate-regulated Standard specific to entities with activities subject to rate regulation.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: variable consideration included in revenue *(Note 4);* carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues; estimates of revenue; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 7)*; amortization rates and carrying value of intangible assets *(Note 8)*; measurement of goodwill; fair value of asset retirement obligations (ARO); fair value of financial instruments *(Note 13)*; provisions for income taxes *(Note 15)*; assumptions used to measure retirement benefits and OPEB *(Note 16)*; and commitments and contingencies *(Note 19)*. Actual results could differ from these estimates.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

REGULATION

Our utility operations within Ontario are regulated by the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates and amounts collected from customers in advance of costs being incurred. Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. The regulator's future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which we operate. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates. We believe that the recovery of our regulatory assets as at December 31, 2022 is probable over the periods described in *Note 5 - Regulatory Matters*.

With the approval of the regulator, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

REVENUE RECOGNITION

Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations for the distribution, storage, transportation and sale of natural gas. For distribution and transportation service arrangements, where the services are simultaneously received and consumed by the customer, revenues are recorded based on regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas. Revenues from storage services are recognized as the storage services are provided.

A significant portion of our operations are subject to regulation and, accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue under such circumstances is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator, which are accounted for under Accounting Standards Codification (ASC) 980 *Regulated Operations*.

PUSH-DOWN ACCOUNTING

Enbridge Gas Distribution Inc. (EGD) elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted US GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by EGD. Upon adopting push-down accounting, the historical cost of EGD's property, plant and equipment and related accounts were adjusted by the remaining unamortized fair value adjustment.

We have also applied push-down accounting with respect to the accounts of Union Gas Limited (Union Gas). The carrying values of certain assets and liabilities of Union Gas transferred to EGD have been adjusted to reflect Enbridge's historical cost as at February 27, 2017, the date upon which Enbridge acquired common control of EGD and Union Gas.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

We use derivative financial instruments to manage our exposure to changes in foreign exchange rates and interest rates. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges. There were no outstanding derivative instruments relating to fair value or net investment hedges as at December 31, 2022 and 2021.

Cash Flow Hedges

We use cash flow hedges to manage our exposure to changes in foreign exchange rates and interest rates related to our unregulated storage revenue. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a reduction to Long-term debt in the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

INCOME TAXES

Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent that taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

FOREIGN CURRENCY TRANSACTIONS

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge Gas operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated to the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting from the translation of monetary assets and liabilities are included in earnings in the period in which they arise.

CASH

We combine cash and bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements.

RECEIVABLES AND CURRENT EXPECTED CREDIT LOSSES

Accounts receivable and other are measured at cost. Interest income is recognized in earnings as it is earned with the passage of time. For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations.

NATURAL GAS IMBALANCES

The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received from, and delivered for, customers. As settlement of imbalances are in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. All natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

GAS INVENTORY

Gas inventories consist of natural gas held in storage. Natural gas held in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of gas purchased is deferred as a liability for future refund, or as an asset for collection, as approved by the OEB.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost, including an allowance for interest incurred during construction as authorized by the regulator. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the regulator. When group assets are retired or otherwise disposed of, gains and losses are generally not reflected in earnings but are booked as an adjustment to accumulated depreciation. Gains and losses on the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the regulator, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the regulator.

LEASES

We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach applied for other long-lived assets.

Lease liabilities and ROU assets require the use of judgment and estimates which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily consist of costs our regulatory authority have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; the fair value adjustment to long-term debt; the difference between the actual cost and approved cost of natural gas reflected in rates; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs. We capitalize costs incurred during the application development stage of internal use software projects. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, we determine the drivers of fair value and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends and industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value is less than its carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of goodwill and comparing that value to its carrying value. If the carrying value, including allocated goodwill, exceeds fair value, goodwill impairment is measured at the amount by which the carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. Fair value is estimated using a discounted cash flow technique. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income and rate base, rate base multiple, capital expenditures and working capital levels.

Due to changes in the macroeconomic environment which has led to a rise in interest rates, we performed a quantitative assessment as at December 1, 2022. The goodwill impairment assessment did not result in an impairment charge.

IMPAIRMENT

We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds its expected undiscounted cash flows, we will calculate fair value based on the discounted cash flows and write the asset down to the extent that the carrying value exceeds the fair value.

ASSET RETIREMENT OBLIGATIONS

ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. Fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

PENSION AND OTHER POSTRETIREMENT BENEFITS

We provide benefits through defined benefit and defined contribution pension plans, as well as defined benefit OPEB plans.

Obligations and net periodic benefit costs for defined benefit pension and OPEB plans are estimated using the projected unit credit method, which is based on years of service, as well as our best estimates of actuarial assumptions such as discount rates, future salary levels, other cost escalations, employees' retirement ages, and mortality.

We determine discount rates using market yields of high-quality corporate bonds with maturities that approximate the estimated timing of future benefit payments.

Plan assets are measured at fair value. The expected return on plan assets is determined using the long-term target asset mixes in our investment policies and long-term market expectations.

Actuarial gains and losses arise from the difference between the actual and expected return on plan assets, and changes in actuarial assumptions such as discount rates. Periodic net actuarial gains and losses and prior service costs are accumulated and presented as follows in the Consolidated Statements of Financial Position:

- as a component of AOCI, for our defined benefit OPEB plans; and
- as a component of Deferred amounts and other assets and/or Other long-term liabilities, for our defined benefit pension plans, to the extent that the net actuarial gains and losses and prior service costs have been permitted or are expected to be permitted by the regulator, to be recovered through future rates.

Net periodic benefit cost is recognized in earnings and includes:

- current service cost;
- interest cost;
- expected return on plan assets;
- amortization of prior service costs over the expected average remaining service life of the plans' active employee group; and
- amortization of net actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the fair value of plan assets, over the expected average remaining service life of the plans' active employee group.

We also record regulatory adjustments for the difference between net periodic benefit costs for accounting versus ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be recovered from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to earnings and OCI on an accrual basis.

For defined contribution plans, our contributions are expensed when the contribution occurs.

COMMITMENTS AND CONTINGENCIES
Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

CHANGES IN ACCOUNTING POLICIES
There were no changes in accounting policies during the year ended December 31, 2022.

ADOPTION OF NEW ACCOUNTING STANDARDS
Disclosures About Government Assistance
Effective January 1, 2022, we adopted Accounting Standards Update (ASU) 2021-10 on a prospective basis. The new standard was issued in November 2021 to increase the transparency of government assistance to business entities. The ASU adds new disclosure requirements for transactions with governments that are accounted for using a grant or contribution accounting model by analogy. The required disclosures include information about the nature of transactions, accounting policy applied, impacted financial statement line items and significant terms and conditions. The adoption of this ASU did not have a material impact on our consolidated financial statements.

4. REVENUES

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Services

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Gas commodity and distribution revenue - residential	**3,771**	2,778
Gas commodity and distribution revenue - commercial and industrial	**1,832**	1,208
Storage revenue	**176**	156
Transportation revenue	**791**	686
Other revenue	**76**	71
Total revenue from contracts with customers	**6,646**	4,899
Other[1]	**(38)**	(6)
Total revenues	**6,608**	4,893

1 Primarily relates to the effects of rate-regulated accounting.

We disaggregate revenues into categories which represent our principal performance obligations. These revenue categories also represent the most significant revenue streams, and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Contract Receivables	Contract Liabilities
(millions of Canadian dollars)		
Balance as at December 31, 2022	**1,359**	**—**
Balance as at December 31, 2021	824	17

Contract receivables represent an unconditional right to consideration where only the passage of time is required before payment of consideration is due, and consist of trade accounts receivable, unbilled revenue and other accrued receivable balances. Contract receivables also consist of trade accounts receivable and unbilled revenue balances for the collection of certain federal carbon levy unit rates, for which we act as an agent.

Contract liabilities represent payments received for performance obligations which have not been fulfilled under our equal monthly payment plan. Revenue recognized during the year ended December 31, 2022 related to obligations under the equal monthly payment plan that existed at December 31, 2021 was $17 million.

Performance Obligations

Revenue category	Nature of Performance Obligation
Gas commodity and distribution revenue	• Supply and delivery of natural gas to customers
Storage and transportation revenue	• Storage and transportation of natural gas on behalf of customers
Other revenue	• Other billing and service fees

There was no material revenue recognized during the year ended December 31, 2022 from performance obligations satisfied in previous periods.

Payment Terms
Payments from distribution customers are received on a continuous basis based on established billing cycles. Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. Payments from storage customers are received monthly under long-term storage capacity contracts. Payments from transportation customers are received on a continuous basis based on established billing cycles or monthly under long-term transportation capacity contracts.

Revenue to be Recognized from Unfulfilled Performance Obligations
Total revenue from performance obligations expected to be fulfilled in future periods is $643 million, of which $354 million is expected to be recognized during the year ending December 31, 2023.

The performance obligations above reflect revenue expected to be recognized in future periods from unfulfilled performance obligations pursuant to contracts with customers for the purchase of natural gas distribution, storage and transportation services. Certain revenues are excluded from the amounts above under the following ASC 606 optional exemptions:

- revenues, such as flow-through costs charged to customers, which are recognized at the amount for which we have the right to invoice our customers; and
- revenue from contracts with customers that have an original expected duration of one year or less.

Variable consideration is also excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be reasonably estimated.

A significant portion of our operations are subject to regulation. Accordingly, the amounts above, in addition to revenues that are not regulated, only include revenue for which the underlying rate has been approved by regulation, where applicable. The revenues excluded from the amounts above could represent a significant portion of our overall revenues and revenue from contracts with customers.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE

Revenue Recognition

Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations as described above. Distribution and transportation service revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas.

Due to regulatory mechanisms, there are circumstances where revenues recognized do not match the amounts billed. Under such circumstances, revenue is recognized in a manner that is consistent with the underlying rate setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator.

Recognition and Measurement of Revenues

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Revenue from products and services transferred over time[1]	**6,571**	4,829
Revenue from products transferred at a point in time[2]	**75**	70
Total revenue from contracts with customers	**6,646**	4,899

1 Revenue from distribution, storage and transportation services.
2 Primarily from Other revenues.

Performance Obligations Satisfied Over Time

For arrangements involving the distribution and transportation of natural gas, where the services are simultaneously received and consumed by the customer, we recognize revenue over time using an output method based on volumes of commodities delivered. The measurement of the volumes delivered corresponds directly to the benefits received by the customers during that period. Revenue from storage services are recognized as the services are provided.

Determination of Transaction Prices

Prices for distribution and transportation services and regulated storage services are prescribed by regulation. Fees for unregulated storage services are determined through negotiations with customers and are based on market rates.

Prices for natural gas sold are driven by market prices and the Quarterly Rate Adjustment Mechanism (QRAM) in place that allows for rates to reflect changes in natural gas prices, subject to regulatory approval.

5. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under US GAAP for non-regulated entities. See *Note 2 - Significant Accounting Policies* for further discussion.

We are regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act*, (1998), which is part of a package of legislation known as the *Energy Competition Act*, (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario.

RATE APPROVALS

Our distribution rates, commencing in 2019, are set under a five-year Incentive Regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires us to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved return on equity.

Under the current OEB-authorized rate structure for our business, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of temporary differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since most of these temporary differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of the related assets. In the absence of rate-regulated accounting, this regulatory Deferred income taxes balance and the related earnings impact would not be recorded.

PURCHASE GAS VARIANCE

The Purchase Gas Variance Account (PGVA) captures the difference between actual and forecasted natural gas prices reflected in rates. Account balances are typically recovered or refunded over a prospective 12-month period through QRAM applications. Due to the significant increase in natural gas prices, the approvals have also included rate mitigation plans intended to ease bill impacts to ratepayers. Specifically, the approved rate mitigation plans extended the PGVA recovery period from 12 months to 24 months in certain applications.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following regulatory assets and liabilities in the Consolidated Statements of Financial Position:

December 31,	**2022**	2021	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Purchase gas variance	**190**	15	2023
Other current regulatory assets	**266**	67	2023
Total current regulatory assets[1] *(Note 6)*	**456**	82	
Long-term regulatory assets			
Deferred income taxes	**1,696**	1,532	Various
Long-term debt[2] *(Note 10)*	**283**	307	2046
Purchase gas variance	**244**	215	2024
Accounting policy changes[3]	**219**	157	Various
Transition impact of accounting changes[4]	**40**	49	2032
Pension plan receivable[5]	**—**	26	Various
Other long-term regulatory assets	**2**	91	Various
Total long-term regulatory assets[1]	**2,484**	2,377	
Total regulatory assets	**2,940**	2,459	
Current regulatory liabilities			
Other current regulatory liabilities	**128**	61	2023
Total current regulatory liabilities[6] *(Note 9)*	**128**	61	
Long-term regulatory liabilities			
Future removal and site restoration reserves[7]	**1,615**	1,543	Various
Pension plan payable[5]	**230**	—	Various
Other long-term regulatory liabilities	**90**	111	Various
Total long-term regulatory liabilities[6]	**1,935**	1,654	
Total regulatory liabilities	**2,063**	1,715	

1 Current regulatory assets are included in Accounts receivable and other, while long-term regulatory assets are included in Deferred amounts and other assets.

2 Represents our regulatory offset to the fair value adjustment to debt acquired in Enbridge's merger with Spectra Energy Corp. (Spectra Energy) and pushed down to Enbridge Gas. The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.

3 This deferral primarily consists of unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas, relating to the period up to Enbridge's merger with Spectra Energy, which were previously recorded in AOCI. The amortization of this balance is recognized as a component of accrual-based pension expenses, which are included in Other income and recovered in rates, as previously approved by the OEB.

4 Represents our right to recover costs resulting from the adoption of the accrual basis of accounting for pension and OPEB costs upon transition to US GAAP in 2012. Pursuant to the OEB rate order, the balance as at December 31, 2012 is to be collected in rates over a 20 year period, commencing in 2013.

5 Represents the regulatory offset to our pension liability/asset to the extent that it is expected to be included in regulator-approved future rates and refunded to or recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense/income would be recorded in earnings and OCI.

6 Current regulatory liabilities are included in Accounts payable and other, while long-term regulatory liabilities are included in Other long-term liabilities.

7 Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

OTHER ITEMS AFFECTED BY RATE REGULATION

Gas Inventories

Natural gas held in storage is recorded in inventory at the reference prices approved by the OEB in the determination of customers' system supply rates. In prior years, Gas inventory included costs related to storage injection and demand charges that, consistent with the regulatory recovery pattern, were recorded in gas inventories during our off-peak months and charged to gas costs during the peak winter months. As of December 31, 2022 we transferred $63 million related to storage injection and demand costs from Gas inventory to the Accounting policy changes deferral account where the balance will reside until we request disposal at the end of current rebasing term. Included in Gas inventory as at December 31, 2021 was $61 million related to storage injection and demand costs. In the absence of rate-regulated accounting, these costs would be expensed as incurred, and inventory would be recorded at the lower of cost or market value.

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2022**	2021
(millions of Canadian dollars)		
Trade receivables and unbilled revenues, net[1]	**1,550**	953
Regulatory assets *(Note 5)*	**456**	82
Gas imbalances	**177**	101
Rebillables receivable	**61**	45
Other	**102**	47
	2,346	1,228

1 Net of allowance for expected credit losses of $71 million as at December 31, 2022 (2021 - $55 million).

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2022**	2021
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas transmission	2.4%	**1,960**	1,854
Gas mains, services and other	2.6%	**14,219**	13,354
Compressors, meters and other operating equipment	4.3%	**3,538**	3,361
Storage	2.6%	**1,145**	1,065
Land and right-of-way[1]	0.9%	**413**	375
Vehicles, office furniture, equipment and other buildings and improvements	9.5%	**511**	453
Under construction	—%	**319**	263
		22,105	20,725
Accumulated depreciation		**(4,954)**	(4,464)
		17,151	16,261
Unregulated property, plant and equipment			
Gas mains, services and other	5.3%	**13**	13
Compressors, meters and other operating equipment	1.3%	**46**	42
Storage	2.8%	**413**	374
Land and right-of-way[1]	1.5%	**40**	38
Vehicles, office furniture, equipment and other buildings and improvements	—%	**13**	—
Under construction	—%	**48**	37
		573	504
Accumulated depreciation		**(123)**	(103)
		450	401
Property, plant and equipment, net		**17,601**	16,662

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.

Depreciation expense, including amounts collected for future removal and site restoration costs, was $638 million for the year ended December 31, 2022 (2021 - $606 million).

Included within depreciation expense is $22 million in incremental depreciation resulting from push-down accounting for the years ended December 31, 2022 and 2021 *(Note 2)*.

8. INTANGIBLE ASSETS

December 31,	**2022**	2021
(millions of Canadian dollars)		
Software and customer information system[1]	**466**	515
Less: Accumulated amortization	**(291)**	(338)
Intangible assets, net	**175**	177

1 The weighted average amortization rate for the years ended December 31, 2022 and 2021 was 11.3% and 12.8%, respectively.

Intangible assets include $21 million of work-in-progress as at December 31, 2022 (2021 - $26 million). Amortization expense for intangible assets for the years ended December 31, 2022 and 2021 was $52 million and $71 million, respectively. The following table presents our expected amortization expense associated with existing intangible assets for the years indicated as follows:

	2023	2024	2025	2026	2027
(millions of Canadian dollars)					
Forecast of amortization expense	54	23	22	18	12

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2022**	2021
(millions of Canadian dollars)		
Trade payables and operating accrued liabilities	**742**	638
Federal carbon program liability	**333**	242
Gas imbalances	**199**	124
Taxes payable	**169**	99
Construction payables and contractor holdbacks	**80**	88
Interest payable	**96**	87
Regulatory liabilities *(Note 5)*	**128**	61
Other	**117**	119
	1,864	1,458

10. DEBT

December 31,	Weighted Average Interest Rate[2]	Maturity	**2022**	2021
(millions of Canadian dollars)				
Medium-term notes	4.1%	2023 - 2052	**9,535**	9,010
Debentures	9.1%	2024 - 2025	**210**	210
Commercial paper and credit facility draws	4.5%	2024	**2,000**	1,515
Other[1]			**(55)**	(49)
Fair value adjustment from push down accounting *(Note 2)*			**283**	307
Total debt			**11,973**	10,993
Current maturities			**(352)**	(126)
Short-term borrowings			**(1,996)**	(1,515)
Long-term debt			**9,625**	9,352

1 Other consists of unamortized discounts, premiums and debt issuance costs.
2 Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2022.

As at December 31, 2022, all outstanding debt was unsecured.

CREDIT FACILITIES

We actively manage our bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of our external credit facility at December 31, 2022:

	Maturity	Total Facility	Draws[2]	Available
(millions of Canadian dollars)				
364 day extendible credit facility	2024[1]	**2,000**	**2,000**	**—**

1 Maturity date is inclusive of the one-year term out provision.
2 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.

In July 2022, we extended our 364 day extendible credit facility to July 2024, which includes a one-year term out provision from July 2023.

The credit facility carries a standby fee of 0.1% on the unused portion and the draws bear interest at market rates.

In addition to this committed credit facility, we had access to Enbridge's demand letter of credit facilities totaling $1.0 billion as at December 31, 2022 and 2021. As at December 31, 2022, $7 million (2021 - $15 million) of letters of credit were issued by us.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2022, we completed the following long-term debt issuances totaling $650 million:

Issue Date	Description	Principal Amount
(millions of Canadian dollars)		
August 2022	4.15% medium-term notes due August 2032	$325
August 2022	4.55% medium-term notes due August 2052	$325

LONG-TERM DEBT REPAYMENT

During the year ended December 31, 2022, we completed the following long-term debt repayment:

Repayment Date	Description	Principal Amount
(millions of Canadian dollars)		
April 2022	4.85% medium-term notes	$125

DEBT COVENANTS

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. We are in compliance with all terms and conditions of our committed credit facility agreement and our Trust Indenture as at December 31, 2022.

INTEREST EXPENSE

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Debentures and term notes	**389**	392
Commercial paper and credit facility draws	**47**	9
Interest on loan from affiliate[1]	**2**	—
Capitalized interest	**(15)**	(7)
	423	394

1 Interest on loan from affiliate is with Enbridge Inc.

11. SHARE CAPITAL

As at December 31, 2022, our authorized share capital consisted of an unlimited number of common shares with no par value and an unlimited number of preference shares. Our Class A and Class B common shares are held by Enbridge Energy Distribution Inc. and Great Lakes Basin Energy LP, respectively. Both classes of common shares are identical in every respect, and dividends cannot be paid to one class without paying dividends to the other. As at December 31, 2022 and 2021, no preference shares were issued and outstanding.

COMMON SHARES

	2022		2021	
December 31,	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Class A				
Balance at beginning of year	**282**	**2,596**	282	2,636
Capital contribution	**—**	**432**	—	527
Return of capital	**—**	**(315)**	—	(567)
	282	**2,713**	282	2,596
Class B				
Balance at beginning of year	**240**	**846**	240	881
Capital contribution	**—**	**368**	—	448
Return of capital	**—**	**(268)**	—	(483)
	240	**946**	240	846
Balance at end of year	**522**	**3,659**	522	3,442

The capital contribution and return of capital transactions to the stated capital of Class A and Class B common shares had no impact on the total shares outstanding.

12. COMPONENTS OF AOCI

Changes in AOCI for the year ended December 31, 2022 and 2021 are as follows:

	2022		
	Cash Flow Hedges	OPEB Adjustment	Total
(millions of Canadian dollars)			
Balance at January 1, 2022	**(31)**	**8**	**(23)**
Other comprehensive income retained in AOCI	**93**	**39**	**132**
Other comprehensive loss/(income) reclassified to earnings	**10**	**(1)**	**9**
	72	**46**	**118**
Tax impact			
Income tax on amounts retained in AOCI	**(25)**	**(10)**	**(35)**
Income tax on amounts reclassified to earnings	**(3)**	**—**	**(3)**
	(28)	**(10)**	**(38)**
Balance at December 31, 2022	**44**	**36**	**80**

	2021		
	Cash Flow Hedges	OPEB Adjustment	Total
(millions of Canadian dollars)			
Balance at January 1, 2021	(64)	(14)	(78)
Other comprehensive income retained in AOCI	29	31	60
Other comprehensive loss reclassified to earnings	17	—	17
	(18)	17	(1)
Tax impact			
Income tax on amounts retained in AOCI	(8)	(9)	(17)
Income tax on amounts reclassified to earnings	(5)	—	(5)
	(13)	(9)	(22)
Balance at December 31, 2021	(31)	8	(23)

13. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK
Our earnings, cash flows and other OCI are subject to movements in natural gas prices, foreign exchange rates and interest rates (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Natural Gas Price Risk
Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by our customers.

Foreign Exchange Risk
Foreign exchange risk is the risk of gain or loss due to the volatility of currency exchange rates. We generate certain revenues, incur expenses and hold cash balances that are denominated in United States (US) dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from US dollar exchange rate variability.

We have implemented a policy to hedge a portion of our US dollar denominated unregulated storage revenue exposures. Qualifying derivative instruments are used to hedge anticipated US dollar denominated revenues and to manage variability in cash flows.

A portion of our natural gas purchases are denominated in US dollars and, as a result, there is exposure to fluctuations in the exchange rate of the US dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to customers, therefore, we have no net exposure to movements in the foreign exchange rate on natural gas purchases.

Interest Rate Risk
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We primarily use qualifying derivative instruments to manage interest rate risk. Pay fixed-receive floating interest rate swaps are used to hedge against the effect of future interest rate movements. As at December 31, 2022, we do not have any floating-to-fixed interest rate swaps outstanding.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have implemented a program to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating-to-fixed interest rate swaps with an average swap rate of 2.6%.

TOTAL DERIVATIVE INSTRUMENTS

We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce our credit risk exposure on financial derivative asset positions outstanding with these counterparties in those particular circumstances.

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments, as well as the maximum potential settlement amounts in the event of the specific circumstances described above. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2022	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts receivable from affiliates					
Interest rate contracts	**79**	**—**	**79**	**—**	**79**
	79	**—**	**79**	**—**	**79**
Total net derivative asset					
Interest rate contracts	**79**	**—**	**79**	**—**	**79**
	79	**—**	**79**	**—**	**79**

December 31, 2021	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts receivable from affiliates					
Interest rate contracts	14	—	14	—	14
	14	—	14	—	14
Deferred amounts and other assets					
Interest rate contracts	12	—	12	—	12
	12	—	12	—	12
Total net derivative asset					
Interest rate contracts	26	—	26	—	26
	26	—	26	—	26

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

December 31, 2022	2022	2023	2024	2025	2026	Thereafter	Total
(millions of Canadian dollars)							
Interest rate contracts - long-term debt	**—**	**900**	**—**	**—**	**—**	**—**	**900**

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on our consolidated earnings and comprehensive income, before the effect of income taxes.

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Amount of unrealized gain recognized in OCI		
Interest rate contracts	**93**	29
	93	29
Amount of loss reclassified from AOCI to earnings		
Interest rate contracts[1]	**10**	17
	10	17

1 Reported within Interest expense, net in the Consolidated Statements of Earnings.

We estimate that a gain of $7 million of AOCI related to unrealized cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest and foreign exchange rates in effect when derivative contracts, that are currently outstanding, mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 12 months as at December 31, 2022.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments, as they become due. In order to manage this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under the committed credit facility and long-term debt, which includes debentures and medium-term notes and, if necessary, additional liquidity is available through intercompany transactions with our ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable us to fund all anticipated requirements. We maintain a current medium-term note shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. We also maintain a committed credit facility with a diversified group of banks and institutions. We are in compliance with all of the terms and conditions of our committed credit facility as at December 31, 2022. As a result, the credit facility is available to us and the banks are obligated to fund us under the terms of the facility.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. We are primarily exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by our large and diversified customer base and the ability to recover an estimate for expected credit losses for utility operations through the rate-making process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default of receivables. Generally, we classify receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which generally require payment in full within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the expected credit loss, which totaled $71 million as at December 31, 2022 (December 31, 2021 - $55 million).

Our expected credit loss is determined based on historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations, using a loss allowance matrix. This estimate is revised each reporting period to reflect current expectations. When we have determined that collection efforts are unlikely to be successful, amounts charged to the expected credit loss account are applied against the impaired accounts receivable.

Entering into derivative financial instruments may also result in exposure to credit risk. We enter into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. As at December 31, 2022, we have $79 million (December 31, 2021 - $26 million) in credit concentrations and credit exposure with Enbridge and its affiliates.

Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair values of financial instruments reflect our best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. We do not have any derivative instruments classified as Level 1.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps, for which observable inputs can be obtained.

As at December 31, 2022, we had Level 2 derivative assets with a fair value of $79 million (December 31, 2021 - $26 million).

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable, or where the observable data does not support a significant portion of the derivative's fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support a Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. We do not have any derivative instruments classified as Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value, including discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, we use observable market prices (interest, foreign exchange and natural gas) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread, as well as the credit default swap spreads associated with our counterparties, in our estimation of fair value.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS
The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. As at December 31, 2022, our long-term debt, including the current portion, had a carrying value of $9.7 billion (December 31, 2021 - $9.2 billion) before debt issuance costs and a fair value adjustment from push down accounting, and a fair value of $8.9 billion (December 31, 2021 - $10.4 billion).

The fair value of financial assets and liabilities, other than derivative instruments and long-term debt, approximate their carrying value due to the short period to maturity.

14. LEASES

LESSEE
We incur operating lease payments related to natural gas transportation, storage and real estate assets. These lease agreements have remaining lease terms of 1 year to 15 years, some of which include options to terminate at our discretion.

For the years ended December 31, 2022 and 2021, we incurred operating lease expenses of $9 million and $8 million, respectively. Operating lease expenses are reported within Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2022 and 2021, operating lease payments made to settle lease liabilities were $9 million and $9 million, respectively. Operating lease payments are reported within Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Consolidated Statements of Financial Position Information

December 31,	**2022**	2021
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases		
Operating lease right-of-use assets, net[1]	**48**	49
Operating lease liabilities - current[2]	**8**	6
Operating lease liabilities - long-term[3]	**40**	43
Total operating lease liabilities	**48**	49
Weighted average remaining lease term		
Operating leases	**7 years**	8 years
Weighted average discount rate		
Operating leases	**3.1%**	3.1%

1 Right-of-use assets are reported within Deferred amounts and other assets in the Consolidated Statements of Financial Position.
2 Current lease liabilities are reported within Accounts payable and other and Accounts payable to affiliates in the Consolidated Statements of Financial Position.
3 Long-term lease liabilities are reported within Other long-term liabilities in the Consolidated Statements of Financial Position.

As at December 31, 2022, we have lease commitments as detailed below:

	Operating leases
(millions of Canadian dollars)	
2023	**9**
2024	**8**
2025	**8**
2026	**8**
2027	**7**
Thereafter	**13**
Total undiscounted lease payments	**53**
Less imputed interest	**(5)**
Total operating lease liabilities	**48**

LESSOR

We receive revenues from operating and sales-type leases primarily related to natural gas equipment and real estate assets. Our lease agreements have remaining lease terms of 4 years to 20 years as at December 31, 2022.

As at December 31, 2022, the following table sets out future lease payments to be received under operating lease and sales-type lease contracts where we are the lessor:

	Operating leases	Sales-type leases
(millions of Canadian dollars)		
2023	**2**	**2**
2024	**1**	**2**
2025	**1**	**2**
2026	**1**	**2**
2027	**1**	**2**
Thereafter	**2**	**18**
Future lease payments to be received	**8**	**28**

15. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	2022	2021
(millions of Canadian dollars)		
Earnings before income taxes	**668**	614
Canadian federal statutory income tax rate	**15%**	15%
Expected federal taxes at statutory rate	**100**	92
Increase/(decrease) resulting from:		
Provincial income taxes	**(39)**	(1)
Effects of rate-regulated accounting[1]	**(62)**	(54)
Part VI.1 tax, net of federal Part I deduction[1]	**76**	30
Other[2]	**(6)**	(4)
Income tax expense	**69**	63
Effective income tax rate	**10.3%**	10.3%

1 The provincial tax component of these items is included in Provincial income taxes above.

2 Includes miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals and entertainment and true-up prior year estimates to reflect the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

For 2022 and 2021, our earnings before income tax are exclusively from Canadian operations. We are subject to taxation in Canada only.

Year ended December 31,	2022	2021
(millions of Canadian dollars)		
Current income tax expense	**84**	78
Deferred income tax recovery	**(15)**	(15)
Income tax expense	**69**	63

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	2022	2021
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(1,823)**	(1,697)
Regulatory assets	**(452)**	(409)
Deferrals	**(27)**	(8)
Pension and OPEB plans	**(42)**	(14)
Financial instruments	**(16)**	—
Other	**(4)**	(7)
Total deferred income tax liabilities	**(2,364)**	(2,135)
Deferred income tax assets		
Future removal and site restoration reserves	**433**	413
Minimum tax credits	**71**	44
Financial instruments	**—**	12
Loss carryforwards	**6**	—
Total deferred income tax assets	**510**	469
Net deferred income tax liabilities	**(1,854)**	(1,666)

The material jurisdiction in which we are subject to potential examinations within Canada is Federal only. We are open to examination by Canadian tax authorities for 2017 to 2022 tax years and are currently under examination for income tax matters in Canada for 2017 to 2019 tax years.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**15**	34
Gross decreases for tax positions of prior year	**(6)**	(16)
Lapses of statute of limitations	**(3)**	(3)
Unrecognized tax benefits at end of year	**6**	15

The unrecognized tax benefits as at December 31, 2022, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the years ended December 31, 2022 and 2021 included no amounts of interest and penalties. As at December 31, 2022 and 2021, the accrued interest and penalties remained at $1 million for both periods.

16. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We provide pension benefits, covering substantially all employees, through contributory and non-contributory registered defined benefit and defined contribution pension plans. We also provide non-registered pension benefits for certain employees through supplemental non-contributory defined benefit pension plans.

Defined Benefit Pension Plan Benefits

Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits

Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

OTHER POSTRETIREMENT BENEFIT PLANS

We provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees, through unfunded defined benefit OPEB plans.

BENEFIT OBLIGATIONS, PLAN ASSETS AND FUNDED STATUS
The following table details the changes in the benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension and OPEB plans:

	Pension		OPEB	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Change in benefit obligation				
Benefit obligation at beginning of year	**2,386**	2,532	**157**	186
Service cost	**60**	63	**2**	3
Interest cost	**64**	51	**4**	4
Participant contributions	**13**	13	**—**	—
Actuarial gain[1]	**(528)**	(161)	**(39)**	(31)
Benefits paid	**(109)**	(112)	**(5)**	(5)
Benefit obligation at end of year[2]	**1,886**	2,386	**119**	157
Change in plan assets				
Fair value of plan assets at beginning of year	**2,415**	2,219	**—**	—
Actual return/(loss) on plan assets	**(129)**	258	**—**	—
Employer contributions	**37**	37	**5**	5
Participant contributions	**13**	13	**—**	—
Benefits paid	**(109)**	(112)	**(5)**	(5)
Fair value of plan assets at end of year	**2,227**	2,415	**—**	—
Overfunded/(underfunded) status at end of year	**341**	29	**(119)**	(157)
Presented as follows:				
Deferred amounts and other assets	**387**	164	**—**	—
Accounts payable and other	**(3)**	(3)	**(7)**	(7)
Other long-term liabilities	**(43)**	(132)	**(112)**	(150)
	341	29	**(119)**	(157)

1 Actuarial gains in 2022 and 2021 primarily due to increase in the discount rates used to measure the benefit obligations.
2 For pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. The accumulated benefit obligation for our pension plans was $1.8 billion and $2.2 billion as at December 31, 2022 and 2021, respectively.

Certain of our pension plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Accumulated benefit obligation	**42**	253
Fair value of plan assets	**—**	181

Certain of our pension plans have projected benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation and fair value of plan assets were as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Projected benefit obligation	**61**	895
Fair value of plan assets	**17**	760

AMOUNT RECOGNIZED IN ACCUMULATED OTHER COMPREHENSIVE INCOME

The amount of pre-tax AOCI relating to our OPEB plans are as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Net actuarial gain	**(51)**	(13)
Total amount recognized in AOCI	**(51)**	(13)

NET PERIODIC BENEFIT COST AND OTHER AMOUNTS RECOGNIZED IN COMPREHENSIVE INCOME

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Service cost	**60**	63	**2**	3
Interest cost[1]	**64**	51	**4**	4
Expected return on plan assets[1]	**(151)**	(131)	**—**	—
Amortization of net actuarial (gain)/loss[1,2]	**8**	28	**(1)**	—
Net periodic benefit (credit)/cost	**(19)**	11	**5**	7
Defined contribution benefit cost	**3**	2	**—**	—
Net pension and OPEB (credit)/cost recognized in Earnings	**(16)**	13	**5**	7
Amount recognized in OCI:				
Amortization of net actuarial gain	**—**	—	**1**	—
Net actuarial gain arising during the year	**—**	—	**(39)**	(31)
Total amount recognized in OCI	**—**	—	**(38)**	(31)
Total amount recognized in Comprehensive income	**(16)**	13	**(33)**	(24)

1 Reported within Other income in the Consolidated Statements of Earnings.
2 Reflects amortization of net actuarial loss arising from pension plans that are recognized as long-term regulatory assets (Note 5).

ACTUARIAL ASSUMPTIONS

The weighted average assumptions made in the measurement of the benefit obligation and net periodic benefit cost of our defined benefit pension and OPEB plans are as follows:

	Pension		OPEB	
	2022	2021	**2022**	2021
Benefit obligations				
Discount rate	**5.3%**	3.2%	**5.3%**	3.2%
Rate of salary increase	**2.8%**	2.9%	**3.0%**	3.0%
Net benefit cost				
Discount rate	**3.2%**	2.6%	**3.2%**	2.6%
Rate of return on plan assets	**6.3%**	6.0%	**N/A**	N/A
Rate of salary increase	**2.9%**	2.3%	**3.0%**	2.4%

ASSUMED HEALTH CARE COST TREND RATES

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	2022	2021
Health care cost trend rate assumed for next year	**4.0%**	4.0%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0%**	4.0%

PLAN ASSETS

We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

Asset Category	Target Allocation	December 31, 2022	December 31, 2021
Equity securities	**40.9%**	**36.9%**	44.9%
Fixed income securities	**34.1%**	**34.3%**	32.2%
Alternatives[1]	**25.0%**	**28.8%**	22.9%

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

	2022				2021			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Cash and cash equivalents	**77**	**—**	**—**	**77**	42	—	—	42
Equity securities								
Canada	**—**	**191**	**—**	**191**	110	123	—	233
Global	**—**	**632**	**—**	**632**	—	853	—	853
Fixed income securities								
Government	**112**	**285**	**—**	**397**	141	294	—	435
Corporate	**—**	**289**	**—**	**289**	—	300	—	300
Alternatives[4]	**—**	**—**	**649**	**649**	—	—	552	552
Forward currency contracts	**—**	**(8)**	**—**	**(8)**	—	—	—	—
Total pension plan assets at fair value	**189**	**1,389**	**649**	**2,227**	293	1,570	552	2,415

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Balance at beginning of year	**552**	466
Unrealized and realized gains	**103**	49
Purchases and settlements, net	**(6)**	37
Balance at end of year	**649**	552

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2023	2024	2025	2026	2027	2028-2032
(millions of Canadian dollars)						
Pension	116	118	121	123	124	646
OPEB	7	7	7	7	7	38

EXPECTED EMPLOYER CONTRIBUTIONS

In 2023, we expect to contribute approximately $5 million and $7 million to the pension plans and OPEB plans, respectively.

17. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Accounts receivable and other	**(681)**	(14)
Accounts receivable from affiliates	**69**	(27)
Regulatory assets	**(597)**	(222)
Gas inventory	**(586)**	(242)
Deferred amounts and other assets	**(2)**	(2)
Accounts payable and other	**275**	196
Accounts payable to affiliates	**82**	(4)
Regulatory liabilities	**275**	(140)
Other long-term liabilities	**(6)**	(18)
	(1,171)	(473)

18. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. Affiliates refer to Enbridge and companies that are either directly or indirectly owned by Enbridge.

Enbridge and its affiliates perform centralized corporate functions for us pursuant to applicable agreements, including legal, accounting, compliance, treasury, employee benefits, information technology and other areas, as well as certain engineering and other services. We reimburse Enbridge for the expenses incurred to provide these services as well as for other expenses incurred on our behalf. In addition, we perform services and incur expenses on behalf of our affiliates, which are subsequently reimbursed. Our expenses and recoveries for these services are recorded in Operating and administrative expense in the Consolidated Statements of Earnings, and are based on the cost of actual services provided or using various allocation methodologies.

Our transactions with entities related through common or joint control and significantly influenced investees are as follows:

Years ended December 31,	2022	2021
(millions of Canadian dollars)		
Operating revenues[1]	**57**	**85**
Gas commodity and distribution costs[2, 3]	**170**	**181**
Operating and administrative expenses[4]	**401**	**308**

1 Includes wholesale gas procurement and transportation services provided to Gazifère Inc. of $43 million (2021 - $30 million), pursuant to a contract negotiated between us and approved by the OEB and Régie de l'énergie.
2 Includes the purchase of gas transportation services of $112 million (2021 - $111 million) from NEXUS Gas Transmission, LLC.
3 Includes the purchase of natural gas, storage, and transportation services of $30 million (2021 - $47 million) from Tidal Energy Marketing Inc. and Tidal Energy Marketing (U.S.) LLC.
4 Includes centralized corporate function transaction costs of $370 million (2021 - $280 million) from Enbridge and its affiliates.

Amounts due from/(to) related parties are as follows:

December 31,	2022	2021
(millions of Canadian dollars)		
Enbridge Inc.[1,2]	**(345)**	18
Enbridge Employee Services Canada Inc.	**(49)**	(61)
Enbridge Pipelines Inc.	**33**	35
Gazifère Inc.	**13**	25
Tidal Energy Marketing Inc.[3]	**20**	19
Other affiliates, net[4]	**6**	19
	(322)	55

1 Includes net qualifying interest cash flow hedges receivable and net derivative receivable balances from affiliate.
2 Balance includes Demand loan from affiliate.
3 Includes affiliate gas imbalance receivable. As at December 31, 2022 total affiliate gas imbalance receivable was $22 million (2021 - $23 million).
4 Includes current portion of operating lease liabilities to affiliates.

SHARE CAPITAL

During the year ended December 31, 2022, common share dividends declared on our Class A and Class B common shares were $56 million (2021 - $108 million) and $48 million (2021 - $92 million), respectively. During 2022, we also completed the return of capital transactions, and received capital contributions, as described in *Note 11 - Share Capital*.

CAPITALIZED SERVICE COSTS

We purchase gas meter services from Lakeside Performance Gas Services Ltd. (Lakeside), such as ongoing meter exchanges and inspections for customers in our franchise area. During the year ended December 31, 2022, we purchased gas meter services from Lakeside totaling $66 million, of which a portion of these costs was expensed to Operating and administrative expense and the remainder capitalized in Property, plant and equipment, net. We will continue purchasing these services at prevailing market prices under normal trade terms.

LEASES

We incur operating lease payments related to natural gas transportation and storage services from various affiliates. As at December 31, 2022 and 2021, affiliate right-of-use assets and lease liabilities were $43 million and $48 million, respectively. See *Note 14 - Leases* for further discussion.

AFFILIATE LOANS

December 31,	**2022**	2021
(millions of Canadian dollars)		
Enbridge Inc.[1]	**318**	—

1 During the year ended December 31, 2022, we borrowed $318 million on the demand loan. The demand loan bears an interest rate of the Canadian Dollar Offered Rate plus a margin of 100 basis points.

See *Note 10 - Debt* for total interest on our loan from affiliate.

19. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2022, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	9,745	350	300	745	650	350	7,350
Purchase of services, pipe and other materials, including transportation[2]	5,935	2,367	675	510	465	361	1,557
Right-of-way commitments	739	13	13	13	13	13	674
Total	16,419	2,730	988	1,268	1,128	724	9,581

1 Includes debentures and term notes, and excludes short-term borrowings, debt discounts, debt issuance costs, finance lease obligations and the fair value adjustment from push-down accounting. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements. Therefore, the actual timing of future cash repayments could be materially different than presented above.

2 Includes capital and operating commitments. Consists primarily of firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; and customer care services.

ENVIRONMENTAL

We are subject to various Canadian federal, provincial and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to natural gas pipeline operations, and we and our affiliates are, at times, subject to environmental remediation obligations at various sites where we operate. We manage this environmental risk through appropriate environmental policies, programs and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of costs arising from environmental incidents associated with our operating activities.

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. We were named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by us for the operation of our MGP.

While these Statements of Claim were filed by the City and the School Board, they were never formally served on us. It was and remains our understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, we entered into an agreement with the City (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with us. To our knowledge, neither the City nor the School Board has taken any steps to advance the lawsuits.

Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time, as there are a number of potential alternative remediation, isolation and containment approaches which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the US for the recovery in rates of costs relating to the remediation of former MGP sites. From 2006 to 2018, the OEB approved the establishment of deferral accounts to record the costs of investigating, defending and dealing with ongoing MGP-related claims. We expect that if it is found that we must contribute to any remediation costs, either as a result of a lawsuit or government order, we may be generally allowed to recover in rates those substantial costs not recovered through insurance or by other means. Accordingly, we believe that the ultimate outcome of these matters will not have a significant impact on our financial position.

Hamilton Contaminated Site

In April 2016, the Ontario Ministry of the Environment, Conservation and Parks (MECP), formerly the Ministry of the Environment and Climate Change, issued a Director's Order (the Order) naming us, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of ours in Hamilton. In May 2016, we appealed the Order, and in June 2016, the Environmental Review Tribunal (the Tribunal), on consent of the MECP's Director, stayed the application of parts of the Order. The Tribunal extended the stay of the Order several times, which allowed the owner of the property, with the cooperation of the adjacent owners, to prepare a plan of action, including discussions with the MECP and other neighbors. On February 4, 2021, the MECP determined that we and other parties have complied with the Order and no further obligations are outstanding. Accordingly, we withdrew our appeal, and the Tribunal has accepted the withdrawal and has closed its file.

OTHER LITIGATION

We are subject to various legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS

We maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

20. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included in our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2022, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

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Please see Exhibit I.1.8-STAFF-14 Attachment 4.xlsx on the OEB’s RDS.

Rating Report

Enbridge Gas Inc.

DBRS

Insight beyond the rating.

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Senior Unsecured Notes	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On September 20, 2019, DBRS Limited (DBRS) confirmed all the rating of Enbridge Gas Inc. (EGI) as listed above. All trends are Stable. EGI was formed following the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas) on January 1, 2019 (the Amalgamation; see the DBRS press release on EGI dated January 2, 2019). The rating confirmations reflect (1) EGI's stable business risk profile, as the Ontario Energy Board's (OEB) decision on the Amalgamation is expected to provide a reasonable framework for EGI to achieve or exceed the allowed return on equity (ROE) and strong cash flow over the deferred rebasing period from 2019 through 2023, and (2) its improved credit metrics in 2018 and for the last 12 months (LTM) ended June 30, 2019, compared with the combined 2017 results of EGD and Union Gas (pro forma by DBRS).

Post Amalgamation, EGI has a large customer base of approximately 3.7 million across Ontario. A large customer base is one of the key factors for EGI to achieve operating efficiency under the price-cap incentive regulation (IR) through 2023. Significant synergy is expected to be achieved over the next five years and EGI is allowed to keep 100% of the earnings up to 150 basis points (bps) in excess the allowed ROE (8.98% for 2019 and will be reset annually). EGI's reliability and flexibility of the natural gas supply has improved significantly compared with EGD as a result of the addition of Union Gas's storage facilities. The ratings incorporate EGI's exposure to volume risk and potential regulatory lag with respect to the recovery of natural gas costs when the price of natural gas increases substantially.

EGI's 2017 pro forma credit metrics (DBRS combined EGD's and Union Gas's 2017 results) were modestly weak, reflecting the fact that Union Gas's metrics were under pressure as a result of a large capex program. However, they improved in 2018 and the LTM 2019 and EGI's credit metrics are expected to improve further over the medium term, reflecting operating efficiency and incremental cash flow from a growing rate base. DBRS expects EGI to fund its future capital projects and to manage its dividend policy in a way that the capital structure will be maintained in line with the regulatory capital structure of 64% debt and 36% equity. DBRS does not expect any positive rating actions during the deferred rebasing period through 2023. However, a negative rating action could be taken if (1) there is an adverse regulatory change that has a negative impact on EGI's business risk profile or (2) EGI experiences a significant deterioration of its credit metrics on a sustained basis. These scenarios are considered unlikely by DBRS.

Financial Information

	6M June 30		12M June 30	Year ended December 31		
Key Pro Forma Credit Metrics	**2019**	**2018**	**2019**	**2018**	**2017PF**	**2016PF**
Cash flow-to-debt	16.6%	15.9%	13.1%	12.3%	10.9%	12.0%
Total debt in capital structure (excl. goodwill)	64.6%	60.2%	64.6%	63.9%	62.8%	62.2%
EBIT interest coverage (times)	3.48	3.23	2.69	2.57	2.18	2.18

Note: 2016PF and 2017PF were prepared by DBRS by combining full-year EGD and Union Gas results.

Issuer Description

EGI is an amalgamation of EGD and Union Gas. It is a regulated natural gas distributor, serving approximately 3.7 million customers across Ontario. Other operations include regulated transportation services as well as regulated and unregulated storage services in Ontario.

Rating Considerations

Strengths

1. Low-risk regulated operations

Substantially all of EGI's assets are regulated and operate under the OEB-approved, five-year price-cap IR plan from 2019 through 2023. The IR plan provides the Company with the following benefits: (a) relatively predictable earnings and cash flow through a formula (see the Regulatory Update section); (b) full recovery of gas supply costs with quarterly adjustments, subject to regulatory review; (c) annual updates for certain costs to be passed through to customers and a reasonable mechanism for capex recovery; and (d) an earnings sharing mechanism with customers, which provides incentives for operational efficiency.

2. Strong franchise area with a very large customer base

EGI is currently the largest regulated natural gas distributor in Canada and is one of the largest in North America, serving approximately 3.7 million residential, commercial and industrial customers across Ontario (approximately 2.2 million from EGD and 1.5 million from Union Gas). The Company's service area is viewed as economically strong compared with other service areas in Canada. EGI's large customer base provides it with the size and scale to operate efficiently during its deferred rebasing period, when efficiency is key to achieve or exceed allowed ROE. EGI's large size also allows it to have more flexibility with its capex planning and stronger access to the debt market.

3. Sizable storage assets provide additional rate base and cash flow

Following the Amalgamation, EGI owns approximately 272 billion cubic feet of natural gas underground storage capacity facilities located at Dawn, the largest natural gas storage hub in Canada, which acts as a gateway for Western Canadian and Appalachian gas supply. EGI's storage facilities are strategically connected to major pipelines that transport natural gas to major Canadian and U.S. markets. A majority of EGI's storage assets is in the regulated rate base. In addition, non-regulated storage assets have generated strong cash flow that reflect high demand in Ontario. DBRS estimates that cash flow from non-regulated storage activities accounts for approximately between 8% and 10% of EGI's consolidated cash flow.

Challenges

1. Volume risk

For EGI's residential and small commercial customers, weather risk remains significant, as forecast volumes (based on normalized weather) are built into the Company's base rates, while actual usage varies with the weather. Therefore, colder-than-normal weather in any given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. For EGI's large industrial customers, volume consumption is sensitive to the economy. However, the volume risk is mitigated through the Company's firm contracts with larger commercial and industrial customers, with charges based on demand.

2. Managing operating costs under the price-cap IR plan

EGI is in the first year of its five-year deferred rebasing IR plan. Managing operating costs is critical for the Company to achieve or exceed the allowed ROE. A significant increase in operating costs can have a negative impact on EGI's earnings and cash flow, and consequently its credit metrics. Earnings below the allowed ROE will not be recovered from customers unless actual ROE is 300 bps below the allowed ROE, at which point the Company can request a regulatory review.

3. Potential regulatory lag

EGI faces potential regulatory lag with respect to the recovery of natural gas costs. Although the Company can pass natural gas costs on to customers with quarterly adjustments, potential regulatory lag still exists. If natural gas costs increase substantially within a short period of time, the Company may have to recover such costs over a longer time frame than it normally does. In addition, EGI could also face regulatory lag with respect to major projects if capital spending amounts are beyond those that can be funded through base rates and if these capital projects do not qualify for recovery through the Incremental Capital Module (ICM) mechanism (see the Regulatory Update section).

Earnings and Outlook

	6M June 30		12M June 30	Year ended December 31		
(CAD millions)	**2019**	**2018**	**2019**	**2018**	**2017PF**	**2016PF**
Gas commodity and distribution revenue	2,592	2,602	4,220	4,230	4,633	3,966
Transportation of gas revenue	457	574	867	984	781	629
Other revenue	42	38	87	83	138	121
Total Revenue	**3,091**	**3,214**	**5,174**	**5,297**	**5,552**	**4,716**
Gas commodity & distribution costs	1,589	1,795	2,470	2,676	3,102	2,374
Operating & administrative	503	499	1,081	1,077	1,047	1,001
Depreciation & amortization	319	318	609	608	595	561
Total Operating Costs	**2,411**	**2,612**	**4,160**	**4,361**	**4,744**	**3,936**
Operating Income	**680**	**602**	**1,014**	**936**	**808**	**780**
Gross interest expense	198	198	396	396	400	391
Capitalized interest	(3)	(3)	(5)	(5)	(15)	(24)
Interest Expense	**195**	**195**	**391**	**391**	**385**	**367**
Operating Income Before Other Income	**485**	**407**	**623**	**545**	**423**	**413**
Other income (expense), net	9	38	51	80	64	73
Operating Profit Before Taxes	**494**	**445**	**674**	**625**	**487**	**486**
Income taxes	61	52	66	57	2	35
Net Income Before Extra. Items	**433**	**393**	**608**	**568**	**485**	**451**
Extraordinary items	(27)	0	(27)	0	0	(16)
Net Income from Continuing Operations	**406**	**393**	**581**	**568**	**485**	**435**
Plus: discontinued operations	0	0	0	0	0	0
Reported Net Income	**406**	**393**	**581**	**568**	**485**	**435**

Note: 2016PF and 2017PF were prepared by DBRS by combining full-year EGD and Union Gas results.

Summary

- A noticeable increase in operating income in 2018 from 2017 reflected (1) a higher transportation revenue and higher distribution charges resulting from increases in the rate base and the customer base and (2) colder weather and higher incremental contributions from expansion projects. This increase was partially offset by higher employee-related costs.
- A meaningful increase in operating income in the first half of 2019 (H1 2019) from the same period in 2018 reflected (1) colder weather in the Company's franchise areas and (2) higher distribution rates and customer base. These positive factors were partially offset by the wind down of EGI's investment in IPL System Inc. (IPL) in December 2018, which are included in "Other Income (Expense) net" (see the Intercompany Transactions section).
- The after-tax $27 million extraordinary item in H1 2019 represented the severance costs ($37 million before tax) related to termination benefits to employees from the amalgamation of EGD and Union Gas.

Outlook

- Assuming normal weather, DBRS expects EGI's earnings to continue to increase modestly throughout the deferred rebasing period, reflecting the continued growth in the rate base and customer base.
- In addition, DBRS expects EGI to benefit from synergy and improvements in operational efficiency through a large customer base of 3.7 million (2.2 million for EGD and 1.5 million for Union Gas).
- However, because EGI's annual rate changes are based on a price-cap formula and operating efficiency is key to achieve or exceed allowed ROE, any material increase in operating costs can have a negative impact on EGI's earnings.
- In August 2017, the Company entered into an agreement to sell its 100%-owned subsidiary in New York State, St. Lawrence Gas, for approximately $76 million (the St. Lawrence Sale). The St. Lawrence Sale is expected to close in the second half of 2019. DBRS does not expect the St. Lawrence sale to have a material impact on EGI's earnings.

Financial Profile

	6M June 30		12M June 30	Year ended December 31		
(CAD millions)	2019	2018	2019	2018	2017PF	2016PF
Operating Cash Flow	**750**	**694**	**1,181**	**1,125**	**1,023**	**1,017**
Capex, equity investments, other	(404)	(778)	(953)	(1,327)	(1,830)	(1,776)
Dividends paid	(625)	(273)	(1,124)	(772)	(664)	(238)
Free cash flow (bef. work. cap. changes)	(279)	(357)	(896)	(974)	(1,471)	(997)
Changes in non-cash work. cap. items	403	912	92	601	265	64
Gross free cash flow	124	555	(804)	(373)	(1,206)	(933)
Business acquisitions, net of cash	0	0	0	0	0	0
Cash extraordinary items	(31)	0	(31)	0	0	0
Proceeds on sale of inv. & other activities (net)	0	0	825	825	0	0
Net Free Cash Flow	**93**	**555**	**(10)**	**452**	**(1,206)**	**(933)**
Change in debt & equivalents	(108)	(630)	(298)	(820)	937	479
Change in note payable - affiliate	0	0	575	575	(253)	191
Change in equity & equivalents	(1)	56	(311)	(254)	530	280
Change in other liabilities	0	0	0	0	0	0
Change in cash & marketable securities	16	19	44	47	(8)	(17)
Funding Sources	**(93)**	**(555)**	**10**	**(452)**	**1,206**	**933**
Total debt in capital structure	48.1%	60.2%	48.1%	47.9%	62.8%	62.2%
Total debt in capital structure 1	64.6%	60.2%	64.6%	63.9%	62.8%	62.2%
Cash flow/total debt	16.6%	15.9%	13.1%	12.3%	9.3%	12.0%
EBIT interest coverage (times)	3.48	3.23	2.69	2.57	2.18	2.18
Fixed-charges coverage (times)	3.48	3.17	2.66	2.51	2.14	2.14
Dividends/Cash flow	83.3%	39.3%	95.2%	68.6%	64.9%	23.4%

Note: 2016PF and 2017PF were prepared by DBRS by combining full-year EGD and Union Gas results.
1 Excludes goodwill.

Summary

- Post Amalgamation, the debt-to-capital ratio, excluding goodwill, increased modestly at the end of 2018 from the combined EGD and Union Gas in 2017. However, this ratio remains at the low end of DBRS's "A" rating range.
- The capital structure in 2017 included the investment of $825 million in IPL and the associated intercompany loan for the IPL investment. This investment and its associated loans wound down in December 2018.
- Cash flow-to-debt ratio in 2018 and LTM 2019 improved significantly from 2017, reflecting higher cash flow from operations (due to stronger earnings) and lower debt levels as a result of the elimination of intercompany loans associated with the investment in IPL. This ratio moved into DBRS's "A" rating range in LTM 2019.
- EBIT-interest coverage continues to benefit from the low-interest-rate environment and stronger operating income in 2018 and LTM 2019. In LTM 2019, this ratio improved and remained solidly at the upper end of DBRS's "A" rating range.
- EGI generated substantial cash flow deficits over the last three years as a result of a large capex program for future growth. The dividend/cash flow ratio has increased since 2018. However, EGI's financing plan is to maintain the debt-to-capital ratio in line with the regulatory capital structure of 64% debt/36% equity. As a result, EGI's debt-to-capital ratio has been maintained relatively stable around or near 64% debt in the past few years.

Outlook

- DBRS expects EGI to continue to generate large free cash flow deficits over the next two years due to large capex and a high dividend payout. Capex for 2019 and 2020 is estimated to be around $1.0 billion each year for system maintenance and to support system upgrades and new capital projects such as the community expansion projects and the Dawn-Parkway Expansion Project (see the Capital Projects section).
- DBRS does not expect EGI to change its financing strategy with respect to maintaining the debt-to-capital ratio (excluding goodwill) at or near the current level throughout the deferred rebasing period.
- DBRS expects EGI's cash flow-to-debt and EBIT-interest coverage ratios to improve modestly over the medium term, reflecting expected operating efficiency and incremental cash flow from a growing rate base.

Liquidity and Long-Term Debt Maturities

Credit Facilities

As at June 30, 2019

(CAD millions)	Total Facilities	Drawn [1]	Available	Maturity
Enbridge Gas Inc.	2,000	917	1,083	2021
St. Lawrence Gas Company, Inc.	17	9	8	2019
Total	**2,017**	**926**	**1,091**	

1 Includes commercial paper issuances, net of discount, that are backed by the $2.0 billion Revolving Term Credit Facility.
St. Lawrence Gas Company, Inc. draws are shown in Liabilities held for sale.

Summary

- Liquidity is supported by predictable cash flow form operations and the availability of credit facilities.
- The $2.0 billion Revolving Term Credit Facility is used to backstop a commercial paper (CP) program of $2.0 billion. EGI's CP program in turn is used to finance working capital changes and to fund capex before terming out with Medium-Term Notes (MTNs). In February 2019, EGI increased its CP program to $2.0 billion from $1.7 billion.
- In this respect, EGI has sufficient liquidity to fund its current working capital and capex needs. However, any combination of cold weather and high gas prices in the future could exhaust the Company's available liquidity. Should that event occur, Enbridge Inc. (Enbridge; rated BBB (high) with a Stable trend by DBRS) is expected to provide liquidity support in a timely manner for EGI.

Debt Maturities

As at June 30, 2019 (CAD million)	2019	2020	2021	2022	2023	Thereafter	Total
EGD Medium-Term Notes and Debentures	0	400	175	0	100	3,105	3,780
Union Gas Medium-Term Notes and Debentures	0	0	200	125	250	2,840	3,415
Total	**0**	**400**	**375**	**125**	**350**	**5,945**	**7,195**

Summary

- EGI's refinancing risk is low in 2019, as it has no long-term debt due in the year. The refinancing risk in 2020 and 2021 is manageable because the MTNs and debentures due in each of these years are modest and within the financing capability of the Company.
- In August 2019, EGI issued $700 million of MTNs to repay its short-term indebtedness and to fund capex. DBRS believes that the debt issuance had no impact on EGI's credit metrics.
- EGI is subject to the issue test covenant in the indenture which states that its total consolidated funded obligations (namely total indebtedness including guarantee that has maturity term longer than 18 months) will not exceed 75% of total consolidated capitalization. EGI is also subject to an EBIT-to-interest covenant of 2.0 times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with the maturity term longer than 18 months.
  - The covenant does not apply to debt issuances for debt refinancing.
  - The Company was in compliance with the covenant as at June 30, 2019.

Intercompany Transactions

- Before the Amalgamation, EGD owned $825 million of Class D, non-voting, redeemable, retractable preferred shares of IPL, which is 100% owned by Enbridge. The Company owed IPL $375 million in loans, which were deeply subordinated to EGD's MTNs and debentures.
- The IPL investment wound down in December 2018 and the $375 million subordinated loan from IPL was paid off.

Regulatory Update

Amalgamation

On August 30, 2018, the OEB issued a decision on the application for the amalgamation of EGI and Union Gas. The OEB's major key determinations in the decision are, among others, as follows:

- The rebasing year is deferred until 2024. The Company asked for a ten-year deferred rebasing period, but the OEB allowed for only five years. DBRS believes that the five-year rebasing period is a credit positive because shorter periods have more certainty with respect to cost recovery and forecasts.
- The annual rate change during the deferred rebasing period is based on a price-cap index (PCI), where PCI growth is driven by an inflation factor using the Gross Domestic Product Implicit Price Index Final Domestic Demand Canada index as the inflation factor, less a productivity factor of zero and a stretch factor of 0.3%. The stretch factor is used in incentive regulation to measure the efficiency of utilities (the actual costs/forecast costs), with superior performance having a lower stretch factor.
- The earnings sharing mechanism during the 2019–2023 period will be on a 50/50 basis between EGI and its ratepayers for all earnings in excess of 150 bps over the allowed ROE. This means that earnings in excess of up to 150 bps will be retained by EGI.
- All capex beyond the amount approved in the deferred rebasing years will be recovered through an ICM (see the next section).
- EGI continues to pass through costs associated with Y factors, with the exception of Cap-and-Trade costs (see the next section). Y factors are costs related to gas commodity and upstream transportation costs, demand-side management cost changes, lost revenue adjustment mechanism changes for the contract market and normalized average consumption/average use.
- EGI is allowed to recover $5.5 million through a Z-factor mechanism ($1.5 million for EGD and $4.0 million for Union Gas). Z factors are related to unforeseen events outside of management.
- During the deferred rebasing period, EGI will continue to purchase market-based storage services to meet the needs of legacy EGD in-franchise customers. This will mean that legacy Union Gas customers continue to benefit from the sale of market-based storage until issues of rate harmonization are considered.

Incremental Capital Module

- ICM is a funding mechanism for significant capital projects for which a utility requires rate recovery in advance of its next regularly scheduled cost of service application.
- The test for ICM is that a capital project is not only required to be part of a capital project that is incremental to the materiality threshold (defined below) but must be driven by capital spending requirements that are extraordinary and unanticipated.
- Materiality means that the amount of capital spending must exceed the OEB-defined threshold (which represents a utility's financial capacities underpinned by existing rates, including growth) and clearly has a significant influence on the operation of the utility. In addition, to be eligible for ICM, the amount of capital spending must be for need and prudence. Need means that the amount of capital spending must be non-discretionary and must be outside of the base upon which the rates are derived. Prudence means that the utility's decision to incur the costs must represent the most cost-effective option for the ratepayers.

Federal Carbon Levy

- Ontario is subject to the federal government's carbon pricing program, which consists of two parts: (1) an output-based pricing system (effective January 1, 2019) and (2) a carbon or fuel charge levied on natural gas (effective April 1, 2019).
- Beginning 2019, on an interim basis, EGI set up an OEB-approved deferral account to capture the costs of the federal carbon charge, which is approximately 3.91 cents/cubic metre. An estimate of an increase in the average residential customer's bill is by $86 per year to $94 per year depending on their location in Ontario. The cost will be borne by customers.

Ontario's Cap and Trade Program

- The Government of Ontario revoked the Ontario cap and trade (OCT) program in July 2018. Registered participants of the OCT program can no longer purchase, sell, trade or otherwise deal with emission allowance and credits.
- In August 2018, the OEB instructed EGD and Union Gas to remove cap and trade charges from customer bills effective October 1, 2018. And in September 2018, the OEB approved EGD's and Union Gas's requests to remove the cap and trade charges from rates and to refund approximately $20 million in the cap and trade deferral accounts to customers.
- The removal of OCT charges is not expected to have any impact on EGI's credit ratios.

Capital Projects

- The Dawn-Parkway Expansion Project: EGI will expand the Dawn-Parkway system to provide Ontario and Northeast U.S. customers with access to the diversity, reliability, security of supply and cost competitiveness of the Dawn Hub. The cost of the project is estimated to be $206 million, and the incremental capacity is 75 million cubic feet per day. The project is expected to be in service in 2021.
- Community Expansion: In March 2019, the Government of Ontario released Ontario Regulation 24/19 (Regulation) allowing for ratepayer funding of specific community expansion projects. There are several projects identified in the Regulation specific to EGI. The total funding for these projects is approximately $34.5 million. EGI has proceeded with a number of community-based system expansion projects in 2019.
- Kingsville Transmission Reinforcement Project: Before the Amalgamation, Union Gas received approval from the OEB to construct a new pipeline, extending from interconnect at the existing Panhandle Line in the Town of Lakeshore to a new station in Kingsville. The cost of the project is estimated to be $122 million. This project is expected to be in service in November 2019.

Enbridge Gas Inc.

Balance Sheet (CAD millions)	June 30	December 31			June 30	December 31	
Assets	**2019**	**2018**	**2017R**	**Liabilities & Equity**	**2019**	**2018**	**2017R**
Cash and cash equivalents	31	17	39	Short-term borrowings	917	1,025	1,445
Restricted cash	2	32	57	Accounts payable	986	1,315	1,386
Accounts receivable and other	922	1,312	1,643	A/P to affiliates	136	55	82
Accounts receivable from affiliates	25	22	47	Liabilities held for sale	37	44	43
Gas inventory	418	687	633	Ltd. due in one year	0	0	412
Assets held for sale, current	23	22	15	**Current Liabilities**	**2,076**	**2,439**	**3,368**
Total Current Assets	**1,421**	**2,092**	**2,434**	Long-term debt	7,530	7,543	7,567
Property, plant and equipment	14,944	14,818	14,344	Other long-term liabilities	1,876	1,773	2,292
Investment in affiliate	0	0	825	Deferred income taxes	1,396	1,319	1,216
Deferred amounts and other assets	2,117	1,931	1,862	Loans from affiliate	950	950	375
Intangible assets	177	209	855	Liabilities held for sale	33	33	34
Goodwill	4,784	4,784	4,784	Preferred shares	0	0	210
Assets held for sale, long-term	105	116	110	Common equity	9,687	9,893	10,152
Total Assets	**23,548**	**23,950**	**25,214**	**Total Liab. & Equity**	**23,548**	**23,950**	**25,214**

R = restated by EGI.

Rating History

	Current	Jan. - 2019	2018
Issuer Rating	A	A	NR
Senior Unsecured Notes	A	A	NR
Commercial Paper	R-1 (low)	R- 1 (low)	NR

Previous Action

- Finalized provisional ratings, January 2, 2019.

Commercial Paper Limit

- $2.0 billion.

Previous Report

EGI does not have any previous reports, but please see the following reports for references:

- Enbridge Gas Distribution Inc.: Rating Report, November 22, 2018.
- Union Gas Limited: Rating Report, February 14, 2018.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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Rating Report
Enbridge Gas Inc.

DBRS Morningstar
September 29, 2020

Contents

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Senior Unsecured Notes	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On September 17, 2020, DBRS Limited (DBRS Morningstar) confirmed all the ratings of Enbridge Gas Inc. (EGI or the Company) as listed above. All trends are Stable. The rating confirmations reflect (1) EGI's stable business risk profile as it is in the second year of the five-year price-cap incentive regulations (IR) lasting through 2023 and there are no expectations of any material changes during this five-year period; (2) its relatively solid credit metrics and DBRS Morningstar's expectation that the credit metrics will improve modestly over the medium term as a result of rate base growth and synergy realization; and (3) solid liquidity and low refinancing risk in the next few years.

The impact of the Coronavirus Disease (COVID-19) pandemic on EGI's operations and financial performance has been modest. Although the pandemic is ongoing, DBRS Morningstar does not expect it to have a material impact on EGI over the near to medium term because EGI operates critical infrastructure and continues to provide an essential service.

The Company's ratings are supported by a stable regulatory framework in Ontario and a very large and economically strong customer base of approximately 3.8 million customers across the province—the largest in Canada and one of the largest in North America. This large customer base is one of the key factors for EGI to achieve operating efficiency under the price-cap IR. Good synergy was realized from the amalgamation of Enbridge Gas Distribution Inc. (EGD) with Union Gas Limited in 2019 and the first half of 2020, and significant synergy is expected to be achieved through 2023. EGI is allowed to keep 100% of the earnings up to 150 basis points (bps) in excess of the allowed return on equity (ROE) (8.52% for 2020, and reset annually). EGI's reliability and the flexibility of its natural gas supply have improved significantly, compared with EGD, as a result of the addition of Union Gas's storage facilities. The ratings incorporate EGI's exposure to volume risk and the potential regulatory lag in the recovery of natural gas costs when the price of natural gas increases substantially.

EGI's key credit metrics have improved since the amalgamation and remained solid for 2019 and the last 12 months (LTM) ended June 30, 2020. DBRS Morningstar expects EGI's credit metrics to improve modestly over the medium term, reflecting operating efficiency (including synergy realization) and incremental cash flow from a growing rate base. Although EGI will likely generate substantial free cash flow deficits over the next few years because of its major capital projects, DBRS Morningstar expects EGI to fund its future capital expenditures (capex) and to manage its dividend policy in such a way that the capital structure will be maintained in line with the regulatory capital structure of 64% debt and 36% equity.

DBRS Morningstar does not expect any positive rating actions during the deferred rebasing period through 2023. However, a negative rating action could be taken should the following events occur: (1) an adverse regulatory change has a negative impact on EGI's business risk profile or (2) EGI experiences a significant deterioration of its credit metrics on a sustained basis. DBRS Morningstar considers these scenarios unlikely.

Financial Information

Enbridge Gas Inc.	6M June 30	6M June 30	12M June 30	Year ended December 31	
Key Pro Forma Credit Metrics	**2020**	**2019**	**2020**	**2019**	**2018**
Cash flow-to-debt (%)	14.9	16.5	12.2	12.7	12.3
Total debt in capital structure (%)	49.0	48.1	49.0	48.3	47.9
Total debt in capital structure (excl. Goodwill) (%)	65.3	64.6	65.3	64.1	63.9
EBIT interest coverage (times)	3.07	3.48	2.44	2.62	2.57

Issuer Description

EGI was created following the amalgamation of Enbridge Gas Distribution Inc. (EGD) with Union Gas on January 1, 2019. The Company is a regulated natural gas distributor, serving approximately 3.8 million customers across Ontario. Other operations include regulated transportation services as well as regulated and unregulated storage services in Ontario. EGI is owned by Enbridge Inc. (54%; rated BBB (high) by DBRS Morningstar) and Westcoast Energy Inc. (46%; rated A (low) by DBRS Morningstar).

Rating Considerations Details

Strengths

1. Low-risk regulated operations

Substantially all of EGI's assets are regulated and operate under the Ontario Energy Board (OEB)-approved, five-year price-cap IR plan from 2019 through 2023. The IR plan provides the Company with the following benefits: (A) relatively predictable earnings and cash flow through a formula (see the Regulatory Update section); (B) full recovery of gas supply costs with quarterly adjustments, subject to regulatory review; (C) annual updates for certain costs to be passed through to customers and a reasonable mechanism for capex recovery; and (D) a mechanism for sharing earnings with customers, which provides incentives for operational efficiency.

2. Strong franchise area with a very large customer base

EGI is currently the largest regulated natural gas distributor in Canada and is one of the largest in North America, serving approximately 3.8 million residential, commercial, and industrial customers across Ontario. The Company's service area is viewed as economically strong compared with other service areas in Canada. EGI's large customer base provides it with the size and scale to operate efficiently during five-year price-cap IR plan. EGI's large size also allows it to maintain a good degree of flexibility with its capex planning.

3. Sizable storage assets provide additional rate base and cash flow

EGI currently owns approximately 272 billion cubic feet of natural gas underground storage capacity facilities located at the Dawn hub, the largest natural gas storage hub in Canada, which acts as a gateway for Western Canadian and Appalachian natural gas supply. EGI's storage facilities are strategically connected to major pipelines that transport natural gas to major Canadian and U.S. markets. A majority of EGI's storage assets is in the regulated rate base. In addition, nonregulated storage assets have generated strong cash flows that reflect high demand in Ontario. DBRS Morningstar estimates that cash flow from nonregulated storage activities accounts for approximately 8% to 10% of EGI's consolidated cash flow.

Challenges

1. Volume risk

For EGI's residential and small commercial customers, weather risk remains significant, as forecast volumes (based on normalized weather) are built into the Company's base rates, while actual usage varies with the weather. Therefore, colder-than-normal weather in any given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. For EGI's large industrial customers, volume consumption is sensitive to the economy. However, the volume risk is partially mitigated through the Company's firm contracts with larger commercial and industrial customers where charges are based on demand. Further, the weather forecast is conducted annually to reflect the latest weather patterns.

2. Managing operating costs under the price-cap IR plan

EGI is in the second year of its five -year price-cap IR plan. Managing operating costs is particularly important for the Company to achieve or exceed the allowed ROE. A significant increase in operating costs can have a negative impact on EGI's earnings and cash flow, and consequently on its credit metrics. Earnings below the allowed ROE will not be recovered from customers unless the actual ROE is 300 bps below the allowed ROE, at which point the Company can request a regulatory review.

3. Potential regulatory lag

EGI faces a potential regulatory lag in the recovery of natural gas costs. Although the Company can pass natural gas costs on to customers with quarterly adjustments, the potential for a regulatory lag still exists. If natural gas costs increase substantially within a short period of time, the Company may have to recover such costs over a longer time frame than it normally does. In addition, EGI could also face regulatory lag with respect to major projects if capital spending amounts are beyond those that can be funded through base rates and if these capital projects do not qualify for recovery through the Incremental Capital Module (ICM) mechanism (see the Regulatory Update section).

Earnings and Outlook

Enbridge Gas Inc.	6M June 30	6M June 30	12M June 30	Year ended December 31	
(CAD millions)	2020	2019	2020	2019	2018
Gas commodity and distribution revenue	2,091	2,592	3,651	4,152	4,242
Transportation of gas revenue	431	457	810	836	972
Other revenue	35	42	80	87	83
Total revenue	**2,557**	**3,091**	**4,541**	**5,075**	**5,297**
Gas Commodity & Distribution Costs	1,127	1,589	1,872	2,334	2,676
Operating & Administrative	506	503	1,073	1,070	1,077
Depreciation & Amortization	318	319	637	638	608
Property Taxes and Other	0	0	0	0	0
Earnings Sharing	0	0	0	0	0
Total Operating Costs	**1,951**	**2,411**	**3,582**	**4,042**	**4,361**
Operating Income	**606**	**680**	**959**	**1,033**	**936**
Gross Interest Expense	208	198	415	405	396
Capitalized Interest	(3)	(3)	(5)	(5)	(5)
Interest Expense	**205**	**195**	**410**	**400**	**391**
Operating Income Before Other Income	**401**	**485**	**549**	**633**	**545**
Other Income (Expense), net	32	9	53	30	80
Operating Profit Before Taxes	**433**	**494**	**602**	**663**	**625**
Income Taxes	38	61	48	71	57
Net Income before Extra. Items	**395**	**433**	**554**	**592**	**568**
Extraordinary Items	(54)	(27)	(63)	(36)	0
Net Income From Continuing Operations	**341**	**406**	**491**	**556**	**568**
Plus: Discontinued Operations	0	0	0	0	0
Reported Net Income	**341**	**406**	**491**	**556**	**568**

Year end 2019 Summary

- Operating income in 2019 increased modestly from 2018, reflecting (1) higher distribution charges due to increase in distribution rates, (2) the increase in the customer base, (3) colder weather and higher incremental contributions from expansion projects, and (4) synergy realized from the amalgamation. This increase was partially offset by higher employee-related costs and higher depreciation and amortization due to higher overall rate base.
- Lower other income in 2019 was a result of the wind-down of the Company's investment in IPL System Inc. (IPL) in December 2018. Extraordinary loss was due to the disposal of St. Lawrence Gas in November 2019.

H1 2020 Summary

- The noticeable decrease in operating income in H1 2020 compared with the same period in 2019 reflected the (1) warmer weather in the Company's franchise areas during the first quarter of 2020 and (2) absence of contribution from St. Lawrence Gas. These factors were partially offset by the higher distribution charges, an increase in customer base, and synergy realized from the amalgamation.
- The higher other income in H1 2020 compared with H1 2019 was largely as a result of higher interest income and foreign currency gains on cash balances denominated in U.S. dollars. The extraordinary item

in H1 2020 represented the severance costs related to termination benefits to employees from the amalgamation of EGD and Union Gas.

Outlook

- Assuming normal weather, DBRS Morningstar expects EGI's earnings to continue to increase modestly throughout the deferred rebasing period, reflecting the continued growth in the rate base and customer base as well as the potential synergy to be realized from the amalgamation.
- However, because EGI's annual rate changes are based on a price-cap formula and operating efficiency is key to achieve or exceed allowed ROE, any material unexpected increase in operating costs can have a negative impact on EGI's earnings.
- On November 1, 2019, the Company sold sell its 100%-owned subsidiary in New York State, St. Lawrence Gas, for approximately $72 million. DBRS Morningstar does not expect the St. Lawrence sale to have a material impact on EGI's earnings.

Financial Profile

Enbridge Gas Inc.	**6M June 30**	**6M June 30**	**12M June 30**	**Year ended December 31**	
(CAD millions)	**2020**	**2019**	**2020**	**2019**	**2018**
Operating cash flow	**697**	**746**	**1,141**	**1,190**	**1,125**
Capex, equity investments, other	(452)	(404)	(1,157)	(1,109)	(1,327)
Dividends paid	(225)	(626)	(536)	(937)	(772)
Free cash flow (bef. work. cap. changes)	**20**	**(284)**	**(552)**	**(856)**	**(974)**
Changes in non-cash work. cap. items	367	403	80	116	601
Gross free cash flow	**387**	**119**	**(472)**	**(740)**	**(373)**
Cash Extraordinary Items	(54)	(27)	(56)	(29)	0
Proceeds on sale of inv. & other activities (net)	0	0	72	72	825
Net free cash flow	**333**	**92**	**(456)**	**(697)**	**452**
Change in debt & equivalents	650	(108)	1,328	570	(820)
Change in note payable - affiliate	(650)	0	(982)	(332)	575
Change in equity & equivalents	(400)	0	87	487	(254)
Change in cash & marketable securities	67	16	23	(28)	47
Funding Sources	**(333)**	**(92)**	**456**	**697**	**(452)**
Total adjusted debt	9,387	9,022	9,387	9,401	9,130
Total debt in capital structure (excluding goodwill) (%)	65.3	64.6	65.3	64.1	63.9
Cash flow/total debt (%)	14.9	16.5	12.2	12.7	12.3
EBIT interest coverage (times)	3.07	3.48	2.44	2.62	2.57
Fixed-charges coverage (times)	3.07	3.48	2.44	2.62	2.51
Dividends/Cash flow (%)	32.3	83.9	47.0	78.7	68.6

Summary

- The debt-to-capital ratio, excluding goodwill, has remained relatively stable since the amalgamation and has stayed at the low end of DBRS Morningstar's "A" rating range. This capital structure is consistent with the regulatory capital structure of 36% equity/64% debt.
- The cash flow-to-debt ratio for the 12 months to June 30, 2020, was negatively affected by lower cash flow for H1 2020. This was because of the negative impact of warmer weather during the first quarter of 2020 and the absence of the cash flow contribution from St. Lawrence Gas. However, this ratio was comparable with 2018 and remained at the lower end of the DBRS Morningstar's "A" rating range.

- EBIT-interest coverage continues to benefit from the low-interest-rate environment and stronger operating income in 2019 and LTM 2020. This ratio remained solidly at the upper end of DBRS Morningstar's "A" rating range.
- EGI has generated substantial free cash flow deficits for the last couple of years as a result of a large capex program for future growth. The dividend/cash flow ratio has increased since 2018. However, EGI's financing plan is to maintain the debt-to-capital ratio in line with the regulatory capital structure of 64% debt/36% equity.

Outlook

- DBRS Morningstar expects EGI to continue to generate significant free cash flow deficits over the next couple of years due to its large capex and high dividend payout. Capex for 2020 and 2021 is estimated to be around $1.0 to $1.5 billion each year for system maintenance and to support system upgrades and new capital projects, such as the community expansion projects and the Dawn-Parkway Expansion Project (see the Capital Projects section).
- DBRS Morningstar does not expect EGI to change its financing strategy of maintaining the debt-to-capital ratio (excluding goodwill) at or near the current level throughout the deferred rebasing period.
- Assuming normal weather, DBRS Morningstar expects EGI's cash flow-to-debt and EBIT-interest coverage ratios to improve modestly over the medium term, reflecting expected operating efficiency and incremental cash flow from a growing rate base.

Liquidity and Long-Term Debt Maturities

Credit Facilities				**As at June 30, 2020**
(CAD millions)	Total Facilities	Drawn[1]	Available	Maturity
Enbridge Gas Inc.	2,000	355	1,645	2021

1 Includes facility draws and commercial paper issuances, net of discount, that are backed by the external credit facility.

Summary

- Liquidity remains solid, supported by predictable cash flow from operations and the availability of sizeable credit facilities.
- The $2.0 billion Revolving Term Credit Facility is used to backstop a commercial paper (CP) program of $2.0 billion. The CP program in turn is used to finance working capital changes and to fund capex before terming out with Medium-Term Notes (MTNs).
- On April 1, 2020, EGI completed a $1.2 billion dual-tranche offering of 10-year and 30-year notes. Partial proceeds from these offerings were used to repay a subordinated promissory note from an affiliate. The rest of the proceeds have solidified EGI's liquidity requirement to fund its current working capital and capex needs. However, any combination of cold weather and high gas prices in the future could exhaust the Company's available liquidity. Should that event occur, Enbridge Inc. (Enbridge; rated BBB (high) with a Stable trend by DBRS Morningstar) is expected to provide liquidity support in a timely manner for EGI.

Debt Maturities

As at June 30, 2020 (CAD million)	**2020**	**2021**	**2022**	**2023**	**2023**	**2024+**	**Total**
EGI MTNs and debentures	400	375	125	350	300	7,545	9,095

Summary

- The refinancing risk in 2020 and 2021 is manageable because the MTNs and debentures due in each of these years are modest and within the financing capability of the Company.
- EGI is subject to the issue test covenant in the indenture, which states that its total consolidated funded obligations (namely total indebtedness, including any guarantee that has a maturity term longer than 18 months) will not exceed 75% of total consolidated capitalization. EGI is also subject to an EBIT-to-interest covenant of 2.0 times, based on EBIT for 12 consecutive months and the annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
    - The covenant does not apply to debt issuances for debt refinancing.
    - The Company was in compliance with the covenant as at June 30, 2020.

Intercompany Transactions

- Before the amalgamation, EGD owned $825 million of Class D, non-voting, redeemable, retractable preferred shares of IPL, which were 100% owned by Enbridge. The Company owed IPL $375 million in loans, which were deeply subordinated to EGD's MTNs and debentures.
- The IPL investment wound down in December 2018 and the $375 million subordinated loan from IPL was paid off.

Regulatory Update

Amalgamation

On August 30, 2018, the OEB issued its decision on the application for the amalgamation of EGI and Union Gas. The OEB's major key determinations in the decision are, among others, as follows:

- The rebasing year is deferred until 2024. The Company asked for a 10-year deferred rebasing period, but the OEB allowed for only five years. DBRS Morningstar believes that the five-year rebasing period is credit positive because shorter periods have more certainty with respect to cost recovery and forecasts.
- The annual rate change during the deferred rebasing period is based on a price-cap index (PCI), where PCI growth is driven by an inflation factor using the Gross Domestic Product Implicit Price Index Final Domestic Demand Canada index as the inflation factor, less a productivity factor of zero and a stretch factor of 0.3%. The stretch factor is used in incentive regulation to measure the efficiency of utilities (the actual costs/forecast costs), with superior performance having a lower stretch factor.
- The earnings sharing mechanism during the 2019–23 period will be on a 50:50 basis between EGI and its ratepayers for all earnings in excess of 150 bps over the allowed ROE. This means that earnings in excess of up to 150 bps will be retained by EGI.
- All capex in excess of the OEB-defined materiality threshold will be recovered through an ICM mechanism, subject to the ICM eligibility criteria during the deferred rebasing term (see the next section).
- EGI continues to pass through costs associated with Y factors. Y factors are costs related to gas commodity and upstream transportation costs, demand-side management cost changes, lost revenue adjustment mechanism changes for the contract market and normalized average consumption/average use.
- EGI may apply to recover $5.5 million on a revenue requirement basis for costs related to unforeseen events outside of the control of management through a Z-factor mechanism.

- During the deferred rebasing period, EGI will continue to purchase market-based storage services to meet the needs of legacy EGD in-franchise customers. This will mean that legacy Union Gas customers continue to benefit from the sale of market-based storage until issues of rate harmonization are considered.

ICM mechanism

- ICM is an OEB funding mechanism for significant capital projects for which a utility requires rate recovery in advance of its next regularly scheduled cost of service (rebasing) application.
- The test for ICM eligibility is that a capital project is not only part of a capital project that is incremental to the materiality threshold (defined below) but must be driven by capital spending requirements that are extraordinary and unanticipated.
- Materiality means that the amount of capital spending must exceed the OEB-defined threshold (which represents a utility's financial capacities underpinned by existing rates, including growth). Any incremental capital amounts approved for rate recovery must fit within the total eligible incremental capital amount and must clearly have a significant influence on the operation of the utility. In addition, to be eligible for ICM, the amount of capital spending must meet the Need and Prudence criteria. Need means that the amount of capital spending must be discrete projects and must be outside of the base upon which the rates are derived. Prudence means that the utility's decision to incur the costs must represent the most cost-effective option for the ratepayers.

Federal carbon levy

- Ontario is subject to the federal government's carbon pricing program, which consists of two parts: (1) an output-based pricing system (effective January 1, 2019) and (2) a carbon or fuel charge levied on natural gas (effective April 1, 2019).
- Beginning in 2019 and on an interim basis, EGI set up an OEB-approved deferral account to capture the costs of the federal carbon charge. On April 1, 2020, the federal carbon charge for natural gas was increased from approximately 3.91 cents per cubic metre to 5.87 cents per cubic metre. The average residential customer's bill is estimated to increase by $141 per year. The cost will be borne by customers.

Capital Projects

- The Dawn-Parkway Expansion Project: EGI will expand the Dawn-Parkway system to provide Ontario and Northeast U.S. customers with access to the diversity, reliability, security of supply, and cost competitiveness of the Dawn Hub. The cost of the project is estimated to be $204 million and the incremental capacity is 83 million cubic feet per day. The project is expected to be in service in 2021.
- Community Expansion: In March 2019, the Government of Ontario released Ontario Regulation 24/19 (Regulation) allowing for ratepayer funding of specific community expansion projects. Several projects identified in the Regulation are specific to EGI. The total funding for these projects is approximately $32.9 million. EGI has proceeded with a number of community-based system expansion projects in 2019 and continued in the first half of 2020.
- Kingsville Transmission Reinforcement Project: Before the amalgamation, Union Gas received approval from the OEB to construct a new pipeline extending from the interconnect at the existing Panhandle Line

in the Town of Lakeshore, Ontario, to a new station in Kingsville, Ontario. This project was placed in service in November 2019.

Balance Sheet

Enbridge Gas Inc.							
Balance Sheet (CAD millions)	**June 30**	**Dec. 31**	**Dec. 31**		**June 30**	**Dec. 31**	**Dec. 31**
Assets	2020	2019	2018	Liabilities & Equity	2020	2019	2018
Cash and cash equivalents	10	77	17	Short-term borrowings	355	898	1,025
Restricted cash	0	0	32	Accounts payable	951	1,369	1,315
Accounts receivable and other	878	1,317	1,312	A/P to affiliates	120	113	55
Accounts receivable from affiliates	48	46	22	Liabilities held for sale	0	0	44
Gas inventory	357	631	687	Ltd. due in one year	602	400	0
Other current assets	0	0	22	**Current Liabilities**	**2,028**	**2,780**	**2,439**
Total Current Assets	**1,293**	**2,071**	**2,092**	Long-term debt	8,792	7,815	7,543
Property, plant, and equipment	15,491	15,418	14,818	Other long-term liabilities	2,066	1,999	1,773
Deferred amounts and other assets	2,333	2,235	1,931	Deferred income taxes	1,496	1,433	1,319
Intangible assets	160	173	209	Loans from affiliate	0	650	950
Goodwill	4,784	4,784	4,784	Liabilities held for sale	0	0	33
Assets held for sale, long-term	0	0	116	Common equity	9,679	10,004	9,893
Total Assets	**24,061**	**24,681**	**23,950**	**Total Liab. & Equity**	**24,061**	**24,681**	**23,950**

Rating History

	Current	**January 2019**	**2018 ***
Issuer Rating	A	A	NR
Senior Unsecured Notes	A	A	NR
Commercial Paper	R-1 (low)	R- 1 (low)	NR

*Note: EGI was formed in January 2019 after the amalgamation of EGD and Union Gas.

Previous Action

- Ratings confirmation, September 20, 2019.

Commercial Paper Limit

- $2.0 billion.

Previous Report

- Enbridge Gas Inc. Rating Report, October 1, 2019.

Note:
All figures are in Canadian dollars unless otherwise noted.

About DBRS Morningstar

DBRS Morningstar is a global credit ratings business with approximately 700 employees in eight offices globally.

On July 2, 2019, Morningstar, Inc. completed its acquisition of DBRS. Combining DBRS' strong market presence in Canada, the U.S., and Europe with Morningstar Credit Ratings' U.S. footprint has expanded global asset class coverage and provided investors with an enhanced platform featuring thought leadership, analysis, and research. DBRS and Morningstar Credit Ratings are committed to empowering investor success, serving the market through leading-edge technology and raising the bar for the industry.

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Rating Report
Enbridge Gas Inc.

DBRS Morningstar
October 5, 2021

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Senior Unsecured Notes	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On September 20, 2021, DBRS Limited (DBRS Morningstar) confirmed the Issuer Rating and Senior Unsecured Notes rating of Enbridge Gas Inc. (EGI or the Company) at "A" and the Company's Commercial Paper rating as R-1 (low). All trends are Stable. The rating confirmations reflect (1) EGI's stable business risk profile as it is in the third year of the five-year price-cap incentive regulations (IR) lasting through 2023, and there are no expectations of any material changes during this period; (2) its relatively solid credit metrics and DBRS Morningstar's expectation that the credit metrics will improve modestly over the medium term as a result of rate base growth and synergy realization; and (3) solid liquidity and low refinancing risk in the next few years.

The impact of the Coronavirus Disease (COVID-19) pandemic on EGI's operations and financial performance during 2020 and year-to-date 2021 has been modest. DBRS Morningstar does not expect the coronavirus to have a material impact on EGI's operational and financial performance because EGI operates critical infrastructure and continues to provide an essential service.

The Company's ratings are supported by a stable regulatory framework in Ontario and a very large and economically strong base of approximately 3.8 million customers across the province—the largest in Canada and one of the largest in North America. This large customer base is one of the key factors allowing EGI to achieve operating efficiency under the price-cap IR. Good synergy was realized from the amalgamation of Enbridge Gas Distribution Inc. (EGD) with Union Gas Limited in 2019 and 2020, and DBRS Morningstar expects significant synergy to be achieved through 2023. EGI is allowed to keep 100% of the earnings up to 150 basis points (bps) in excess of the allowed return on equity (ROE); beyond 150 bps, the split between customers and EGI is 50:50. EGI's reliability and the flexibility of its natural gas supply have improved significantly, compared with EGD, as a result of the addition of Union Gas' storage facilities. The ratings incorporate EGI's exposure to volume risk and the potential regulatory lag in the recovery of natural gas costs when the price of natural gas increases substantially.

A slight weakness in EGI's key credit metrics for 2020 compared with 2019 was caused by the lower volume of natural gas consumption because of warmer weather conditions. However, EGI's key credit metrics for 2020 and the last 12 months (LTM) ended June 30, 2021, remained solid and were supportive of the current ratings. DBRS Morningstar expects EGI's credit metrics to improve modestly over the medium term, reflecting operating efficiency (including synergy realization) and incremental cash flow from a growing rate base. Although EGI will likely generate substantial free cash flow deficits over the next few years because of its major capital projects, DBRS Morningstar expects EGI to fund its future capital expenditures (capex) and to manage its dividend policy in such a way that the capital structure will be maintained in line with the regulatory capital structure of 64% debt and 36% equity. As a result, DBRS Morningstar does not expect the financing of EGI's capex to have a material impact on its credit metrics in the medium term.

DBRS Morningstar does not expect any positive rating actions in the near term. However, it could take a negative rating action should the following events occur: (1) an adverse regulatory change has a negative impact on EGI's business risk profile, or (2) EGI experiences a significant deterioration of its credit metrics on a sustained basis. DBRS Morningstar considers these scenarios unlikely.

Financial Information

Enbridge Gas Inc.	6M June 30	6M June 30	12M June 30	Year ended December 31		
Key Credit Metrics	**2021**	**2020**	**2021**	**2020**	**2019**	**2018**
Cash flow-to-debt (%)	14.8	14.9	12.2	11.9	12.7	12.3
Total debt in capital structure (%)	50.0	49.0	50.0	49.2	48.3	47.9
Total debt in capital structure (excl. goodwill) (%)	66.0	65.3	66.0	64.8	64.1	63.9
EBIT interest coverage (times)	3.28	3.07	2.58	2.50	2.62	2.57

Issuer Description

EGI was created following the amalgamation of EGD with Union Gas on January 1, 2019. The Company is a regulated natural gas distributor, serving approximately 3.8 million customers across Ontario. Other operations include regulated transportation services as well as regulated and unregulated storage services in Ontario. Enbridge Inc. (rated BBB (high) by DBRS Morningstar) directly owns 54% and indirectly owns 100% of EGI.

Rating Considerations

Strengths

1. Low-risk regulated operations

Almost all of EGI's assets are regulated and operate under the Ontario Energy Board (OEB)-approved, five-year price-cap IR plan from 2019 through 2023. The IR plan provides the Company with the following benefits: (A) relatively predictable earnings and cash flow through a formula (see the Regulatory Update section); (B) full recovery of gas supply costs with quarterly adjustments, subject to regulatory review; (C) annual updates for certain costs to be passed through to customers and a reasonable mechanism for capex recovery; and (D) a mechanism for sharing earnings with customers, which provides incentives for operational efficiency.

2. Strong franchise area with a very large customer base

EGI is currently the largest regulated natural gas distributor in Canada and is one of the largest in North America, serving approximately 3.8 million residential, commercial, and industrial customers across Ontario. The Company's service area is viewed as economically strong compared with other service areas in Canada. EGI's large customer base provides it with the size and scale to operate efficiently during the five-year price-cap IR plan. EGI's large size also allows it to maintain a good degree of flexibility with its capex planning.

3. Sizable storage assets provide additional rate base and cash flow

EGI currently owns approximately 276 billion cubic feet of natural gas underground storage capacity facilities located at the Dawn Hub, the largest natural gas storage hub in Canada, which acts as a gateway for Western Canadian and Appalachian natural gas supply. EGI's storage facilities are strategically connected to major pipelines that transport natural gas to major Canadian and U.S. markets. The majority of EGI's storage assets is in the regulated rate base. In addition, nonregulated storage assets have generated strong cash flows that reflect high demand in Ontario. DBRS Morningstar estimates that cash flow from nonregulated storage activities accounts for approximately 8% to 10% of EGI's consolidated cash flow.

Challenges

1. Volume risk

For EGI's residential and small commercial customers, weather risk remains significant, as forecast volumes (based on normalized weather) are built into the Company's base rates, while actual usage varies with the weather. Therefore, colder-than-normal weather in any given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. For EGI's large industrial customers, volume consumption is sensitive to the economy. However, the volume risk is partially mitigated through the Company's firm contracts with larger commercial and industrial customers where charges are based on demand. Further, the weather forecast is conducted annually to reflect the latest weather patterns.

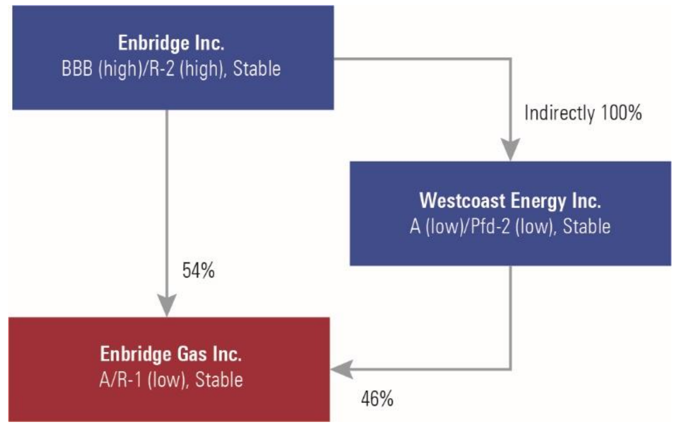
2. Managing operating costs under the price-cap IR plan

EGI is in the third year of its five-year price-cap IR plan. Managing operating costs is particularly important for the Company to achieve or exceed the allowed ROE. A significant increase in operating costs can have a negative impact on EGI's earnings and cash flow, and consequently on its credit metrics. Earnings below the allowed ROE will not be recovered from customers unless the actual ROE is 300 bps below the allowed ROE, at which point the Company can request a regulatory review.

3. Potential regulatory lag

EGI faces a potential regulatory lag in the recovery of natural gas costs. Although the Company can pass natural gas costs on to customers with quarterly adjustments, the potential for a regulatory lag still exists. If natural gas costs increase substantially within a short period of time, the Company may have to recover such costs over a longer time frame than it normally does. In addition, EGI could also face regulatory lag with respect to major projects if capital spending amounts are beyond those that can be funded through base rates and if these capital projects do not qualify for recovery through the Incremental Capital Module (ICM) mechanism (see the Regulatory Update section).

Simplified Organizational Structure



Note: Enbridge Gas Inc. represents approximately 14% of the consolidated EBITDA of Enbridge Inc.

Enbridge Inc: It is a diversified energy company with the following segments: Liquids Pipelines (approximately 54% of DBRS Morningstar-adjusted segment EBITDA in the LTM ended March 31, 2021), Gas Transmission and Midstream (29%), Gas Distribution and Storage (14%), Renewable Power Generation (4%), and Energy Services (-1%).

Westcoast Energy Inc.: In addition of owning a 46% interest in EGI, Westcoast Energy Inc. also owns (1) the federally regulated B.C. Pipeline natural gas transmission system and (2) a 78% interest in the federally regulated Maritime & Northeast Pipeline Limited Partnership Canada, a natural gas transmission system in Eastern Canada.

Earnings and Outlook

Enbridge Gas Inc.	6M June 30	6M June 30	12M June 30	Year ended December 31		
(CAD millions)	**2021**	**2020**	**2021**	**2020**	**2019**	**2018**
Gas commodity and distribution revenues	2,260	2,091	3,800	3,631	4,152	4,242
Storage, transportation, and other revenues	474	466	892	884	923	1,055
Total revenue	**2,734**	**2,557**	**4,692**	**4,515**	**5,075**	**5,297**
Gas commodity & distribution costs	1,257	1,127	1,942	1,812	2,334	2,676
Operating & administrative expenses	504	506	1,061	1,063	1,070	1,077
Depreciation & amortization expenses	340	318	677	655	638	608
Total operating costs	**2,101**	**1,951**	**3,680**	**3,530**	**4,042**	**4,361**
Operating Income	**633**	**606**	**1,012**	**985**	**1,033**	**936**
Gross interest expense	198	208	407	417	405	396
Capitalized interest	(3)	(3)	(5)	(5)	(5)	(5)
Interest expense, net	**195**	**205**	**402**	**412**	**400**	**391**
Operating Income Before Other Income	**438**	**401**	**610**	**573**	**633**	**545**
Other income (expense), net	16	32	40	56	30	80
Operating Profit Before Taxes	**454**	**433**	**650**	**629**	**663**	**625**
Income taxes	53	38	93	78	71	57
Net income before extraordinary items	**401**	**395**	**557**	**551**	**592**	**568**
Extraordinary items	0	(54)	0	(54)	(36)	0
Reported net income	**401**	**341**	**557**	**497**	**556**	**568**

YE2020 Summary

- Operating income in 2020 dropped slightly from 2019, largely reflecting (1) warmer weather in 2020 than 2019 and (2) higher employee-related costs and higher depreciation and amortization from a higher overall rate base. The decrease was partially offset by (1) the increase in the customer base and (2) synergy realized from the amalgamation.

H1 2021 Summary

- The increase in operating income in H1 2021 compared with the same period in 2020 reflected (1) the increase in rates and customer base and (2) synergies realized from the amalgamation. However, the increase in the operating income was partially offset by warmer weather in the Company's franchise areas during the Q1 2021.

Outlook

- Assuming normal weather, DBRS Morningstar expects EGI's operating income to continue to increase modestly throughout the deferred rebasing period, reflecting the continued growth in the rate base and customer base as well as the potential synergy to be realized from the amalgamation.
- However, because EGI's annual rate changes are based on a price-cap formula and operating efficiency, any materially unexpected increase in operating costs can have a negative impact on EGI's operating income.

Financial Profile

Enbridge Gas Inc.	6M June 30	6M June 30	12M June 30	Year ended December 31		
(CAD millions)	**2021**	**2020**	**2021**	**2020**	**2019**	**2018**
Operating cash flow	732	697	1,198	1,163	1,190	1,125
Capital expenditures (incl. intangible assets)	(527)	(452)	(1,260)	(1,185)	(1,109)	(1,327)
Dividends paid	(626)	(625)	(1,251)	(1,250)	(1,250)	(772)
Free cash flow (bef. work. cap. changes)	**(421)**	**(380)**	**(1,313)**	**(1,272)**	**(1,169)**	**(974)**
Changes in noncash working capital items	332	367	58	93	116	601
Gross free cash flow	**(89)**	**(13)**	**(1,255)**	**(1,179)**	**(1,053)**	**(373)**
Cash extraordinary items	0	(54)	0	(54)	(29)	0
Proceeds on sale of inv. & other activities (net)	0	0	0	0	72	825
Net free cash flow	**(89)**	**(67)**	**(1,255)**	**(1,233)**	**(1,010)**	**452**
Change in debt & equivalents	89	650	454	1,015	570	(820)
Change in note payable – affiliate	0	(650)	0	(650)	(332)	575
Change in equity & equivalents	0	0	800	800	800	(44)
Change in cash & marketable securities	0	67	1	68	(28)	47
Funding sources	**89**	**67**	**1,255**	**1,233**	**1,010**	**(242)**
Total debt in capital structure (%)	50.0	49.0	50.0	49.2	48.3	47.9
Cash flow/total debt (%)	14.8	14.9	12.2	11.9	12.7	12.3
EBIT interest coverage (times)	3.28	3.07	2.58	2.50	2.62	2.57
Fixed-charges coverage (times)	3.28	3.07	2.58	2.50	2.62	2.51
Dividends/cash flow (%)	85.5	89.7	104.4	107.5	105.0	68.6

Summary

- All credit metrics remained solid in the LTM to June 30, 2021, reflecting relatively stable cash flow and reasonable debt leverage.
- The debt-to-capital ratio, excluding goodwill, has remained relatively stable since the amalgamation and has stayed at the low end of DBRS Morningstar's "A" rating range. This capital structure level is consistent with the regulatory capital structure of 36% equity/64% debt.
- The cash flow-to-debt ratio for the LTM to June 30, 2021, improved modestly from 2020 because of higher cash flow for H1 2021 compared with H1 2020. Cash flow in H1 2020 was negatively affected by warmer weather.
- EBIT-interest coverage for the LTM to June 30, 2021, continued to benefit from the low-interest rate environment and solid operating income for the period.
- EGI has generated substantial free cash flow deficits for the last couple of years as a result of a large capex program in 2019 and 2020 (averaging $1.15 billion each year). Most of growth capex was spent on growth capital projects that were approved by the regulator (see below).
- DBRS Morningstar notes that the dividend/cash flow ratio has increased since 2018. This increase combined with large growth projects caused EGI to require substantial external funds to finance its cash flow deficits.
- However, EGI's financing plan has been to maintain the debt-to-capital ratio in line with the regulatory capital structure of 64% debt/36% equity.

Outlook

- DBRS Morningstar expects EGI to continue to generate free cash flow deficits over the next couple of years because of its large capex and high dividend payout. Capex for 2021 and 2022 is estimated to be between $1.4 billion and $1.6 billion each year. A substantial amount of capex each year will be for system upgrades and new capital projects, such as the Community Expansion projects and the Lake Shore KOL Replacement Project (see the Capital Projects section).
- DBRS Morningstar does not expect EGI to change its financing strategy of maintaining the debt-to-capital ratio (excluding goodwill) at or near the current level throughout the deferred rebasing period.
- Assuming normal weather, DBRS Morningstar expects EGI's cash flow-to-debt and EBIT-interest coverage ratios to improve modestly over the medium term, reflecting expected operating efficiency and incremental cash flow from a growing rate base.

Liquidity and Long-Term Debt Maturities

Credit Facilities				As at June 30, 2021
(CAD millions)	**Total Facilities**	**Drawn**[1]	**Available**	**Maturity**
Enbridge Gas Inc.	2,000	1,410	590	2022

1 Includes facility draws and commercial paper issuances, net of discount, that are backed by the external credit facility.

Summary

- Liquidity remains solid, supported by predictable cash flow from operations and the availability of sizeable credit facilities.
- The $2.0 billion Revolving Term Credit Facility is used to backstop a commercial paper program of $2.0 billion.
- On September 15, 2021, EGI completed a $900 million dual-tranche offering of 10-year and 30-year notes. The debt issuance is not expected to have any material impact on EGI's credit metrics because most net proceeds repaid the company's indebtedness, which had financed its capex program.
- DBRS Morningstar notes that in the event where there is extremely cold weather and gas prices are rising sharply, the Company would have to seek temporarily support from its parent, Enbridge. Currently, EGI has access to Enbridge's letter of credit facilities totalling $2.0 billion.

Debt Maturities

As at June 30, 2021 (CAD million)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026+**	**Total**
EGI medium-term notes and debentures	175	125	350	300	745	6,800	8,495

Summary

- The refinancing risk in the next four years is manageable because the medium-term notes and debentures due in each of these years are modest and within the financing capability of the Company.
- EGI is subject to the issue test covenant in the indenture, which states that its total consolidated funded obligations (namely total indebtedness, including any guarantee that has a maturity term longer than 18 months) will not exceed 75% of total consolidated capitalization. EGI is also subject to an EBIT-to-interest covenant of 2.0 times, based on EBIT for 12 consecutive months and the annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
  - The covenant does not apply to debt issuances for debt refinancing.
  - The Company was in compliance with the covenant as at June 30, 2021.

Regulatory Update

2021 Rate Application

- On June 30, 2020, EGI filed for phase 1 of the application for setting rates for 2021. OEB approved this application on November 6, 2020.
- On October 15, 2021, EGI filed phase 2 application for 2021 ICM funding requirements. On May 6, 2021, OEB approved $124 million of the capital funding.

2022 Rate Application

- On June 30, 2021, EGI filed for phase 1 of the application for setting rates for 2022. The approval on this application is expected in H2 2021.

Amalgamation

On August 30, 2018, the OEB issued its decision on the application for the amalgamation of EGI and Union Gas. The OEB's major key determinations in the decision are, among others, as follows:

- The rebasing year is deferred until 2024. The Company asked for a 10-year deferred rebasing period, but the OEB allowed for only five years. DBRS Morningstar believes that the five-year rebasing period is credit positive because shorter periods have more certainty with respect to cost recovery and forecasts.
- The annual rate change during the deferred rebasing period is based on a price-cap index (PCI), where PCI growth is driven by an inflation factor using the Gross Domestic Product Implicit Price Index Final Domestic Demand Canada index as the inflation factor, less a productivity factor of zero and a stretch factor of 0.3%. The stretch factor is used in incentive regulation to measure the efficiency of utilities (the actual costs/forecast costs), with superior performance having a lower stretch factor.
- The earnings sharing mechanism during the 2019–23 period will be on a 50:50 basis between EGI and its ratepayers for all earnings in excess of 150 bps over the allowed ROE. This means that earnings in excess of up to 150 bps will be retained by EGI.
- All capex in excess of the OEB-defined materiality threshold will be recovered through an ICM mechanism, subject to the ICM eligibility criteria during the deferred rebasing term (see the next section).
- EGI continues to pass through costs associated with Y factors. Y factors are costs related to gas commodity and upstream transportation costs, demand-side management cost changes, lost revenue adjustment mechanism changes for the contract market, and normalized average consumption/average use.
- EGI may apply to recover $5.5 million on a revenue requirement basis for costs related to unforeseen events outside of the control of management through a Z-factor mechanism.
- During the deferred rebasing period, EGI will continue to purchase market-based storage services to meet the needs of legacy EGD in-franchise customers. This will mean that legacy Union Gas customers continue to benefit from the sale of market-based storage until issues of rate harmonization are considered.

ICM Mechanism

- ICM is an OEB funding mechanism for significant capital projects for which a utility requires rate recovery in advance of its next regularly scheduled cost of service (rebasing) application.
- The test for ICM eligibility is that a capital project is not only part of a capital project that is incremental to the materiality threshold (defined below) but must be driven by capital spending requirements that are extraordinary and unanticipated.
- Materiality means that the amount of capital spending must exceed the OEB-defined threshold (which represents a utility's financial capacities underpinned by existing rates, including growth). Any incremental capital amounts approved for rate recovery must fit within the total eligible incremental capital amount and must clearly have a significant influence on the operation of the utility. In addition, to be eligible for ICM, the amount of capital spending must meet the Need and Prudence criteria. Need means that the amount of capital spending must be discrete projects and must be outside of the base upon which the rates are derived. Prudence means that the utility's decision to incur the costs must represent the most cost-effective option for ratepayers.

Federal Carbon Levy

- Ontario is subject to the federal government's carbon pricing program, which consists of two parts: (1) an output-based pricing system (effective January 1, 2019) and (2) a carbon or fuel charge levied on natural gas (effective April 1, 2019).
- Beginning in 2019 and on an interim basis, EGI set up an OEB-approved deferral account to capture the costs of the federal carbon charge. On April 1, 2020, the federal carbon charge for natural gas was increased to 7.83 cents per cubic metre from approximately 5.87 cents per cubic metre. The average residential customer's bill is estimated to increase by $43 to $47 per year. The cost will be borne by customers.

Capital Projects

- The Dawn-Parkway Expansion Project: The purpose of the expansion was to provide Ontario and Northeast U.S. customers with access to the diversity, reliability, security of supply, and cost competitiveness of the Dawn Hub. However, because of changes in demand and uncertainties resulting from the coronavirus pandemic, on October 22, 2020, EGI withdrew the application for the Dawn-Parkway system expansion.
- Community Expansion: In March 2019, the government of Ontario released Ontario Regulation 24/19 (Regulation) allowing for ratepayer funding of specific community expansion projects. Several projects identified in the Regulation are specific to EGI. The total funding for these projects is approximately $32.9 million. On June 8, 2021, the Ontario government approved funding for phase 2 of the program. Under phase 2, EGI will be provided with up to $214 million for funding assistance to deliver 25 community expansion and two economic development projects. These projects are expected to be in service from 2022 through 2027.
- Lake Shore KOL Replacement Project: The replacement project of approximately 4.5 kilometres of natural gas pipeline and ancillary facilities of the Cherry to Bathurst segment of the Kipling Oshawa Loop along Lake Shore Boulevard in the City of Toronto. The project is expected to be placed into service in H2 2022.

Balance Sheet

Enbridge Gas Inc.							
Balance Sheet ($ millions)	June 30	Dec. 31	Dec. 31		June 30	Dec. 31	Dec. 31
Assets	**2021**	**2020**	**2019**	**Liabilities & Equity**	**2021**	**2020**	**2019**
Cash and cash equivalents	9	9	77	Short-term borrowings	1,410	1,121	898
Accounts receivable and other	855	1,161	1,317	Accounts payable	1,094	1,295	1,369
Accounts receivable from affiliates	78	92	46	A/P to affiliates	185	134	113
Gas inventory	477	659	631	Ltd. due in one year	303	376	400
Total Current Assets	**1,419**	**1,921**	**2,071**	**Current Liabilities**	**2,992**	**2,926**	**2,780**
Property, plant, and equipment	16,107	15,866	15,418	Long-term debt	8,467	8,606	7,815
Deferred amounts and other assets	2,577	2,492	2,235	Other long-term liabilities	2,171	2,166	1,999
Intangible assets	165	174	173	Deferred income taxes	1,597	1,522	1,433
Goodwill	4,784	4,784	4,784	Loans from affiliate	0	0	650
Total Assets	**25,052**	**25,237**	**24,681**	Common equity	9,825	10,017	10,004
				Total Liab. & Equity	**25,052**	**25,237**	**24,681**

Rating History

	Current	**2020**	**2019***
Issuer Rating	A	A	A
Senior Unsecured Notes	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)

*Note: EGI was formed in January 2019 after the amalgamation of EGD and Union Gas.

Previous Action

- Ratings confirmation, September 17, 2020.

Commercial Paper Limit

- $2.0 billion.

Previous Report

- Enbridge Gas Inc.: Rating Report, September 29, 2020.

Note:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrsmorningstar.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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We rate more than 3,000 issuers and nearly 60,000 securities worldwide, providing independent credit ratings for financial institutions, corporate and sovereign entities, and structured finance products and instruments. Market innovators choose to work with us because of our agility, transparency, and tech-forward approach.

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Rating Report
Enbridge Gas Inc.

DBRS Morningstar
September 27, 2022

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Senior Unsecured Notes	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On September 21, 2022, DBRS Limited (DBRS Morningstar) confirmed the Issuer Rating and Senior Unsecured Notes rating of Enbridge Gas Inc. (EGI or the Company) at “A” and the Company’s Commercial Paper rating at R-1 (low). All trends are Stable. The rating confirmations reflect the following considerations:

1. EGI maintained a stable business risk profile as it is in the fourth year of the five-year price-cap incentive regulations (IR) ending at the end of 2023. The IR framework for EGI has been stable and DBRS Morningstar does not expect any material changes during this IR period.

2. EGI's financial performance remained solid, with improved credit metrics for the 12 months ended June 30, 2022. Furthermore, DBRS Morningstar expects the credit metrics to improve modestly over the medium term as a result of rate base growth and synergy realization (see below).

3. EGI's liquidity remained solid despite a significant increase in the Purchase Gas Variance Account (PGVA), which captures the difference between actual and forecast natural gas prices. As of June 30, 2022, the PGVA balance was $780 million. The recovery of the PGVA balance was approved by the Ontario Energy Board (OEB). However, the recovery period extends to 24 months, instead of 12 months. At the end of June 2022, approximately $380 million of EGI's $2.0 billion credit facility was available. In August 2022, the Company's liquidity improved considerably as EGI issued $650 million in long-term debt, which was partially used to paydown the Company's short-term indebtedness. DBRS Morningstar expects that, as in the past, in the event that EGI requires more liquidity to finance its natural gas inventory for the winter distribution, its parent, Enbridge Inc. (rated BBB (high) with a Stable trend by DBRS Morningstar), will step in and provide temporary liquidity.

The Company’s ratings are supported by a stable regulatory framework in Ontario and a very large and economically strong base of approximately 3.8 million customers across the province—the largest in Canada and one of the largest in North America. This large customer base is one of the key factors allowing EGI to achieve operating efficiency under the price-cap IR. Good synergy was realized in the past three years from the amalgamation of Enbridge Gas Distribution Inc. (EGD) with Union Gas Limited

(Union Gas), and DBRS Morningstar expects significant synergy to be achieved through 2023. EGI's reliability and the flexibility of its natural gas supply have improved significantly, compared with stand-alone EGD, as a result of the significant addition of Union Gas's storage facilities. The ratings incorporate EGI's exposure to volume risk and the potential regulatory lag in the recovery of natural gas costs when the price of natural gas increases substantially.

Although EGI will likely generate substantial free cash flow deficits over the next few years because of its major capital projects (which DBRS Morningstar estimates to be between $1.4 billion and $1.5 billion for new projects and system upgrades) and a high dividend payout ratio. Funding of cash flow deficits has been with new debt issued by EGI and equity injections from the parent. DBRS Morningstar expects EGI to continue to fund its future capital expenditures (capex) in such a way that the capital structure will be maintained in line with the regulatory capital structure of 64% debt and 36% equity. As a result, DBRS Morningstar does not expect the financing of EGI's capex to have a material impact on its credit metrics in the medium term.

DBRS Morningstar does not expect any positive rating actions in the near term. However, it could take a negative rating action should the following events occur: (1) an adverse regulatory change that would have a negative impact on EGI's business risk profile, or (2) a significant deterioration of EGI's credit metrics on a sustained basis that would no longer support the current ratings. DBRS Morningstar considers these scenarios unlikely.

Financial Information

Enbridge Gas Inc.	6M June 30	6M June 30	12M June 30	Year ended December 31		
Key Credit Metrics	**2022**	**2021**	**2022**	**2021**	**2020**	**2019**
Cash flow-to-debt (%)	15.0	14.8	12.0	11.4	12.1	12.7
Total debt in capital structure (%)	49.9	50.1	49.9	50.8	49.4	48.4
Total debt in capital structure (excl. goodwill) (%)	64.3	66.2	64.3	65.8	65.1	64.3
EBIT interest coverage (times (x))	3.34	3.20	2.49	2.41	2.36	2.55

Issuer Description

Enbridge Gas Inc is a regulated natural gas distributor with connections to approximately 3.8 million meters serving residential, commercial, and industrial customers across Ontario. Other operations include regulated transportation services as well as regulated and unregulated storage services in Ontario. Enbridge Inc. owns 100% of EGI (54% directly and 46% indirectly).

Rating Considerations

Strengths

1. Low-risk regulated operations

Almost all of EGI's assets are regulated and operate under the OEB-approved, five-year price-cap IR plan from 2019 through 2023. The IR plan provides the Company with the following benefits: (A) relatively predictable earnings and cash flow through a formula (see the Regulatory Update section); (B) full recovery of gas supply costs with quarterly adjustments, subject to regulatory review; (C) annual updates for certain costs to be passed through to customers and a reasonable mechanism for capex recovery;

and (D) a mechanism for sharing earnings with customers, which provides incentives for operational efficiency.

2. Strong franchise area with a very large customer base

EGI is currently the largest regulated natural gas distributor in Canada and is one of the largest in North America, serving approximately 3.8 million residential, commercial, and industrial customers across Ontario. The Company's service area is viewed as economically strong compared with other service areas in Canada. EGI's large customer base provides it with the size and scale to operate efficiently during the five-year price-cap IR plan. EGI's large size also allows it to maintain a good degree of flexibility with its capex planning.

3. Sizable storage assets provide additional rate base and cash flow

As at June 30, 2022, EGI owned approximately 281 billion cubic feet (bcf; 276 bcf in 2021) of natural gas underground storage capacity facilities located at the Dawn Hub, the largest natural gas storage hub in Canada, which acts as a gateway for Western Canadian and Appalachian natural gas supply. EGI's storage facilities are strategically connected to major pipelines that transport natural gas to major Canadian and U.S. markets. The majority of EGI's storage assets is in the regulated rate base. In addition, nonregulated storage assets have generated strong cash flows that reflect high demand in Ontario. DBRS Morningstar estimates that cash flow from nonregulated storage activities accounts for approximately 8% to 10% of EGI's consolidated cash flow.

Challenges

1. Volume risk

For EGI's residential and small commercial customers, weather risk remains significant, as forecast volumes (based on normalized weather) are built into the Company's base rates, while actual usage varies with the weather. Therefore, colder-than-normal weather in any given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. For EGI's large industrial customers, volume consumption is sensitive to the economy. However, the volume risk is partially mitigated through the Company's firm contracts with larger commercial and industrial customers where charges are based on demand. Further, the weather forecast is conducted annually to reflect the latest weather patterns.

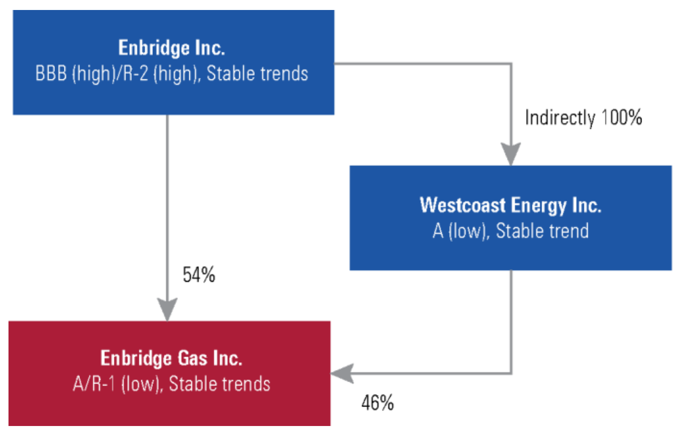
2. Managing operating costs under the price-cap IR plan

EGI is in the fourth year of its five-year price-cap IR plan. Managing operating costs is particularly important for the Company to achieve or exceed the allowed ROE. A significant increase in operating costs can have a negative impact on EGI's earnings and cash flow, and consequently on its credit metrics. Earnings below the allowed ROE will not be recovered from customers unless the actual ROE is 300 basis points (bps) below the allowed ROE, at which point the Company can request a regulatory review.

3. Potential regulatory lag

EGI faces a potential regulatory lag in the recovery of natural gas costs. Although the Company can pass natural gas costs on to customers with quarterly adjustments, the potential for a regulatory lag still exists. If natural gas costs increase substantially within a short period of time, the Company may have to recover such costs over a longer time frame than it normally does. In addition, EGI could also face regulatory lag with respect to major projects if capital spending amounts are beyond those that can be funded through base rates and if these capital projects do not qualify for recovery through the Incremental Capital Module (ICM) mechanism (see the Regulatory Update section).

Simplified Organizational Structure



Note: EGI represented approximately 13% of the consolidated EBITDA of Enbridge Inc. in 12 months ended March 31, 2022.

Enbridge Inc.: It is a diversified energy company with the following segments: Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation, and Energy Services (see DBRS Morningstar's rating report dated July 27, 2022, for details).

Westcoast Energy Inc.: In addition to owning a 46% interest in EGI, Westcoast Energy Inc. also owns (1) the federally regulated B.C. Pipeline natural gas transmission system and (2) a 78% interest in the federally regulated Maritime & Northeast Pipeline Limited Partnership, a natural gas transmission system in Eastern Canada (see DBRS Morningstar's rating report dated June 29, 2022, for details).

Earnings and Outlook

Enbridge Gas Inc.	6M June 30	6M June 30	12M June 30	Year ended December 31		
(CAD millions)	**2022**	**2021**	**2022**	**2021**	**2020**	**2019**
Gas commodity and distribution revenues	2,982	2,260	4,718	3,996	3,631	4,252
Storage, transportation, and other revenues	512	474	935	897	884	923
Total Revenue	**3,494**	**2,734**	**5,653**	**4,893**	**4,515**	**5,075**
Gas commodity & distribution costs	1,927	1,257	2,816	2,146	1,812	2,334
Operating & administrative expenses	549	504	1,150	1,105	1,063	1,070
Depreciation & amortization expenses	337	340	674	677	655	638
Total operating costs	**2,813**	**2,101**	**4,640**	**3,928**	**3,530**	**4,042**
Operating Income	**681**	**633**	**1,013**	**965**	**985**	**1,033**
Gross interest expense	204	198	407	401	417	405
Capitalized interest	(4)	(3)	(8)	(7)	(5)	(5)
Interest expense, net	**200**	**195**	**399**	**394**	**412**	**400**
Operating Income Before Other Income	**481**	**438**	**614**	**571**	**573**	**633**
Other income (expense), net	38	16	65	43	56	30
Operating Profit Before Taxes	**519**	**454**	**679**	**614**	**629**	**663**
Income taxes	(46)	(53)	(56)	(63)	78	71
Net income before extraordinary items	**473**	**401**	**623**	**551**	**551**	**592**
Extraordinary items	0	0	0	0	(54)	(36)
Reported net income	**473**	**401**	**623**	**551**	**497**	**556**

YE2021 Summary

- Operating income in 2021 increased modestly from 2020, largely reflecting (1) the absence of employee severance, transition, and transformation costs in 2021; (2) synergy realized from the amalgamation; and (3) increases in rates and customer base.

H1 2022 Summary

- The increase in operating income in H1 2022 compared with the same period in 2021 reflected (1) colder weather in the first half of 2022, (2) higher distribution charges resulting from increases in rates and customer base, and (3) synergies realized from the amalgamation. However, the increase in the operating income was partially offset by higher operating expenses largely driven by the timing of expenditures.

Outlook

- Assuming normal weather, DBRS Morningstar expects EGI's operating income to continue to increase modestly throughout the deferred rebasing period, reflecting the continued growth in the rate base and customer base as well as the potential synergy to be realized from the amalgamation.
- However, because EGI's annual rate changes are based on a price-cap formula and operating efficiency, any materially unexpected increase in operating costs can have a negative impact on EGI's operating income.

Financial Profile

Enbridge Gas Inc.	6M June 30	6M June 30	12M June 30	Year ended December 31		
(CAD millions)	**2022**	**2021**	**2022**	**2021**	**2020**	**2019**
Operating cash flow	**798**	**732**	**1,279**	**1,213**	**1,163**	**1,190**
Capital expenditures (incl. intangible assets)	(619)	(452)	(1,472)	(1,380)	(1,109)	(1,185)
Dividends paid	(687)	(626)	(1,311)	(1,250)	(1,250)	(1,250)
Free cash flow (bef. work. cap. changes)	**(508)**	**(421)**	**(1,504)**	**(1,417)**	**(1,272)**	**(1,169)**
Changes in noncash working capital items	16	332	(789)	(473)	116	93
Gross free cash flow	**(492)**	**(89)**	**(2,293)**	**(1,890)**	**(1,179)**	**(1,053)**
Cash extraordinary items	0	0	0	0	(54)	(29)
Proceeds on sale of inv. & other activities (net)	12	0	12	0	0	72
Net free cash flow	**(480)**	**(89)**	**(2,281)**	**(1,890)**	**(1,233)**	**(1,010)**
Change in debt & equivalents	230	89	1,056	915	1,015	570
Change in note payable – affiliate	0	0	0	0	(650)	(332)
Change in equity & equivalents	500	0	1,475	975	800	800
Change in cash & marketable securities	250	0	(250)	0	68	(28)
Funding sources	**480**	**89**	**2,281**	**1,890**	**1,233**	**1,010**
Total debt in capital structure (%) [1]	64.3	66.2	64.3	65.8	65.1	64.3
Cash flow/total debt (%)	15.0	14.8	12.0	11.4	12.1	12.7
EBIT interest coverage (x)	3.34	3.20	2.49	2.41	2.36	2.55
Dividends/cash flow (%)	86.1	85.5	102.5	103.1	106.1	105.0

1 Excluding goodwill.

Summary

- All credit metrics remained solid in the last twelve months (LTM) ended June 30, 2022, reflecting relatively stable cash flow and reasonable debt leverage.
- The debt-to-capital ratio, excluding goodwill, has remained relatively stable since the amalgamation and has stayed at the low end of DBRS Morningstar's "A" rating range. This capital structure level is consistent with the regulatory capital structure of 36% equity/64% debt.
- The cash flow-to-debt ratio for the LTM ended June 30, 2022, improved modestly from 2021 because of higher cash flow for H1 2022 compared with H1 2021.
- EBIT-interest coverage for the LTM ended June 30, 2022, continued to benefit from solid operating income for the period.
- EGI has generated substantial free cash flow deficits for the last couple of years as a result of a large capex program in 2020 and 2021 (averaging $1.35 billion each year). Most of growth capex was spent on growth capital projects that were approved by the regulator (see below).
- DBRS Morningstar notes the dividend/cash flow ratio has increased since 2018. This increase combined with large growth projects caused EGI to require substantial external funds to finance its cash flow deficits.
- However, EGI's financing plan has been to maintain the debt-to-capital ratio in line with the regulatory capital structure of 64% debt/36% equity.

Outlook

- DBRS Morningstar expects EGI to continue to generate free cash flow deficits over the next couple of years because of its large capex and a high dividend payout. Capex for 2022 and 2023 is estimated to be between $1.4 billion and $1.5 billion each year. A substantial amount of capex each year will be for system upgrades and new capital projects, such as the Lake Shore Kipling Oshawa Loop Replacement Project (Lakeshore KOL Replacement Project), Natural Gas Expansion Project and Panhandle Regional Expansion Project (see the Capital Projects section).
- DBRS Morningstar does not expect EGI to change its financing strategy of maintaining the debt-to-capital ratio (excluding goodwill) at or near the current level throughout the deferred rebasing period.
- Assuming normal weather, DBRS Morningstar expects EGI's cash flow-to-debt and EBIT-interest coverage ratios to improve modestly over the medium term, reflecting expected operating efficiency and incremental cash flow from a growing rate base.

Liquidity and Long-Term Debt Maturities

Credit Facilities As at June 30, 2022

(CAD millions)	Total Facilities	Drawn[1]	Available	Maturity
Enbridge Gas Inc.[1]	2,000	1,620	380	2023

1 Includes facility draws and commercial paper issuances, net of discount, that are backed by the external credit facility.

Summary

- Liquidity remains solid, supported by predictable cash flow from operations and the availability of sizable credit facilities.
- The $2.0 billion Revolving Term Credit Facility is used to backstop a commercial paper program of $2.0 billion. In August 2022, EGI completed a $650 million dual-tranche offering of 10-year and 30-year notes. The debt issuance is not expected to have any material impact on EGI's credit metrics because most net proceeds were used to pay down the Company's short-term indebtedness.
- DBRS Morningstar notes in the event where there is extremely cold weather and gas prices are rising sharply, the Company would have to seek temporary support from its parent, Enbridge Inc. Currently, EGI has access to Enbridge Inc.'s letter of credit facilities totalling $2.0 billion.

Debt Maturities

As at June 30, 2022 (CAD millions)	2022	2023	2024	2025	2026	2027+	Total
EGI medium-term notes and debentures	0	350	300	745	650	7,050	9,095

Summary

- The refinancing risk in the next four years is manageable because the medium-term notes and debentures due in each of these years are modest and within the financing capability of the Company.
- EGI is subject to the issue test covenant in the indenture, which states that its total consolidated funded obligations (namely total indebtedness, including any guarantee that has a maturity term longer than 18 months) will not exceed 75% of total consolidated capitalization. EGI is also subject to an EBIT-to-interest covenant of 2.0 times, based on EBIT for 12 consecutive months and the annual pro forma interest requirements for all debt with a maturity term longer than 18 months:
  - The covenant does not apply to debt issuances for debt refinancing.
  - The Company was in compliance with the covenant as at June 30, 2022.

Regulatory Update

EGI 2022 Rate Application

- EGI filed its application in two phases. Phase 1 was filed in June 2021 for the setting of rates for 2022. In October 2021, the OEB approved a Phase 1 Settlement proposal and Interim Rate Order effective January 1, 2022. In April 2022, the OEB issued its decision on Phase 2, which was filed in October 2021, addressing ICM funding requirements. The OEB decision approved $127 million of EGI's capital funding, which was incorporated into final rates, effective July 1, 2022.

EGI 2023 Rate Application

- In June 2022, EGI filed for Phase 1 of the application for setting rates for 2023 (the 2023 Application). EGI expects to receive an OEB decision on Phase 1 of the 2023 Application in the second half of 2022. EGI does not anticipate its 2023 capital investment to require incremental funding during the final year of its Price Cap IR term (see below).

Amalgamation

On August 30, 2018, the OEB issued its decision on the application for the amalgamation of EGI and Union Gas. The OEB’s major key determinations in the decision were, among others, as follows:

- The rebasing year is deferred until 2024. The Company asked for a 10-year deferred rebasing period, but the OEB allowed for only five years. DBRS Morningstar believes the five-year rebasing period is credit positive because shorter periods have more certainty regarding cost recovery and forecasts.
- The annual rate change during the deferred rebasing period is based on a price-cap index (PCI), where PCI growth is driven by an inflation factor using the Gross Domestic Product Implicit Price Index's Final Domestic Demand index as the inflation factor, less a productivity factor of zero and a stretch factor of 0.3%. The stretch factor is used in incentive regulation to measure the efficiency of utilities (the actual costs/forecast costs), with superior performance having a lower stretch factor.
- The earnings sharing mechanism during the 2019–23 period will be on a 50:50 basis between EGI and its ratepayers for all earnings in excess of 150 bps over the allowed ROE. This means earnings in excess of up to 150 bps will be retained by EGI.
- All capex in excess of the OEB-defined materiality threshold will be recovered through an ICM mechanism, subject to the ICM eligibility criteria during the deferred rebasing term (see the next section).
- EGI continues to pass through costs associated with Y-factors. The Y-factors are costs related to gas commodity and upstream transportation costs, demand-side management cost changes, lost revenue adjustment mechanism changes for the contract market, and normalized average consumption/average use.
- The Z-factor materiality threshold will be set at $5.5 million on a revenue requirement basis.
- During the deferred rebasing period, EGI will continue to purchase market-based storage services to meet the needs of legacy EGD's in-franchise customers. This will mean that legacy Union Gas customers continue to benefit from the sale of market-based storage until issues of rate harmonization are considered.

ICM Mechanism

- ICM is an OEB funding mechanism for significant capital projects, for which a utility requires rate recovery in advance of its next regularly scheduled cost of service (COS; rebasing) application.
- The test for ICM eligibility is that a capital project is not only part of a capital project that is incremental to the materiality threshold (defined below) but must also be driven by capital spending requirements that are extraordinary and unanticipated.
- Materiality means the amount of capital spending must exceed the OEB-defined threshold (which represents a utility's financial capacities underpinned by existing rates, including growth). Any incremental capital amounts approved for rate recovery must fit within the total eligible incremental capital amount and must clearly have a significant influence on the operation of the utility. In addition, to be eligible for ICM, the amount of capital spending must meet the need and prudence criteria. Need means the total amount of capital spending must be for discrete projects and must be outside of the base upon which the rates are derived. Prudence means the utility's decision to incur the costs must represent the most cost-effective option for ratepayers.

Capital Project - Significant Commercially Secured Projects (Between 2022 and 2027, all approved by OEB)

- Storage Enhancement: This project is part of a larger delta-pressuring project to increase deliverability and storage capacity at EGI's storage facilities. The additional deliverability and storage capacity will be sold as part of the Company's unregulated storage portfolio. The estimated capital cost is $80 million.
- Lake Shore KOL Replacement Project: The replacement project of approximately 4.5 kilometres of natural gas pipeline and ancillary facilities of the Cherry to Bathurst Streets segment of the Kipling Oshawa Loop along Lake Shore Boulevard in the City of Toronto. The project is expected to be placed into service in Q4 2022. The estimated capital cost is $130 million.
- Natural Gas Expansion Program (NGEP): Under Phase 2 of the NGEP, EGI will be provided up to $214 million in funding assistance to deliver 25 community expansion and two economic development projects throughout Ontario. The estimated capital cost is $121 million (net of maximum funding assistance).
- Panhandle Regional Expansion: Expansion of the Panhandle Transmission System, which supplies natural gas from the Dawn Hub to customers in Southern Ontario, west of Dawn, consists of construction of the Panhandle Loop and Leamington interconnects, and is expected to receive a full COS-regulated return upon OEB approval. In-service dates are targeted for November 2023 and November 2024. The estimated capital cost is $314 million.

ESG Factors

There are currently no environmental, social, or governance (ESG) factors affecting the ratings of EGI.

* A Relevant Effect means that the impact of the applicable ESG risk factor has not changed the rating or rating trend on the issuer.
A Significant Effect means that the impact of the applicable ESG risk factor has changed the rating or trend on the issuer.
If any factor is proposed to have a Significant Effect, this should be reflected in the Press Release

ESG Factor		ESG Credit Consideration Applicable to the Credit Analysis: Y/N		Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*
Environmental		Overall:	N	N
	Emissions, Effluents, and Waste	Do we consider that the costs or risks for the issuer or its clients result, or could result, in changes to an issuerÆs financial, operational, and/or reputational standing?	N	N
	Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs and/or will such costs increase over time affecting the long term credit profile?	N	N
	Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	N	N
	Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?	N	N
	Climate and Weather Risks	In the near term, will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact? In the long term, will the issuer's or client's business activities and infrastructure be materially affected financially by a 2C rise in temperature?	N	N
Social		Overall:	N	N
	Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services could pose a financial or regulatory risk to the issuer?	N	N
	Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts that could result in a material financial or operational impact?	N	N
		Do violations of rights create a potential liability that can negatively affect the issue's financial wellbeing or reputation?	N	N
		Human Capital and Human Rights	N	N
	Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	N	N
	Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could it result, in financial penalties or client attrition to the issuer?	N	N
	Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	N	N
	Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	N	N
	Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	N	N
Governance		Overall:	N	N
	Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	N	N
		Are there any political risks that could impact the issuer's financial position or its reputation?	N	N
		Bribery, Corruption, and Political Risks	N	N
	Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	N	N
	Corporate / Transaction Governance	Does the issuer's corporate structure allow for appropriate board and audit independence?	N	N
		Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	N	N
		Does the Board and/or management have a formal framework to assess climate-related financial risks to the issuer?	N	N
		Corporate / Transaction Governance	N	N
	Institutional Strength, Governance, and Transparency (Governments Only)	Compared with other governments, do institutional arrangements provide a similar degree of accountability, transparency, and effectiveness?	N	N
		Are regulatory and oversight bodies protected from inappropriate political influence?	N	N
		Are government officials exposed to public scrutiny and held to high ethical standards of conduct?	N	N
		Institutional Strength, Governance, and Transparency (Governments Only)	N	N
		Consolidated ESG Criteria Output:	N	N

Balance Sheet

	Enbridge Gas Inc.						
Balance Sheet (CAD millions)	June 30	Dec. 31	Dec. 31		June 30	Dec. 31	Dec. 31
Assets	**2022**	**2021**	**2020**	**Liabilities & Equity**	**2022**	**2021**	**2020**
Cash and cash equivalents	9	9	9	Short-term borrowings	1,620	1,515	1,121
Accounts receivable and other	1,447	1,228	1,161	Accounts payable	1,360	1,458	1,295
Accounts receivable from affiliates	170	156	92	A/P to affiliates	354	113	134
Gas inventory	658	897	659	Ltd. due in one year	0	126	376
Total Current Assets	**2,284**	**2,290**	**1,921**	**Current Liabilities**	**3,334**	**3,212**	**2,926**
Property, plant, and equipment	16,974	16,662	15,866	Long-term debt	9,343	9,352	8,606
Deferred amounts and other assets	3,049	2,677	2,492	Other long-term liabilities	2,118	2,012	2,166
Intangible assets	180	177	174	Deferred income taxes	1,774	1,666	1,522
Goodwill	4,784	4,784	4,784	Common equity	10,702	10,348	10,017
Total Assets	**27,271**	**26,590**	**25,237**	Total Liab. & Equity	27,271	26,590	25,237

Rating History

	Current	**2021**	**2020**	**2019***
Issuer Rating	A	A	A	A
Senior Unsecured Notes	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

*Note: EGI was formed in January 2019 after the amalgamation of EGD and Union Gas.

Previous Action

- Ratings confirmation, September 20, 2021.

Commercial Paper Limit

- $2.0 billion.

Previous Report

- Enbridge Gas Inc.: Rating Report, October 5, 2021.

Note:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrsmorningstar.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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S&P Global Ratings

Research

Research Update:

Enbridge Gas Inc. Assigned 'A-' Issuer Credit Rating; Outlook Stable

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Research Update:

Enbridge Gas Inc. Assigned 'A-' Issuer Credit Rating; Outlook Stable

Rating Action Overview

- On Jan. 2, 2019, S&P Global Ratings assigned its 'A-' long-term and 'A-2' short-term issuer credit ratings to Ontario-based gas distribution utility operator Enbridge Gas Inc. (EGI). The outlook is stable.
- EGI is formed through the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Ltd. (Union), both of which were separate stand-alone subsidiaries of Enbridge Inc. (Enbridge) previously.
- The ratings on EGI's senior unsecured debentures that are assumed from EGD and Union are unchanged at 'A-'.
- At the same time, we assigned our 'A-2' global and 'A-1 (Low)' Canada National Scale ratings to EGI's commercial paper program.
- The stable outlook on Enbridge Gas Inc. reflects S&P Global Ratings' expectation that the company will continue to focus on and generate stable and predictable cash flows from its regulated gas distribution operations, and that the company's adjusted funds from operations (AFFO) to debt will range from 12%-13%, for the 2019-2021 forecast period.

Rating Action Rationale

Our ratings assignment follows the formation of Enbridge Gas Inc. (EGI), a new legal entity established after the Ontario Energy Board (OEB) approved the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Ltd. (Union) in 2018, with revised terms. Prior to forming EGI, both EGD and Union were separate stand-alone subsidiaries of parent company Enbridge. Key terms of the amalgamation include:

- EGI will primarily operate under inflation-indexed rates through 2023, before starting a new rate application cycle in 2024.
- The annual revenue increases through 2023 will be subject to a productivity stretch factor constraint of 0.3%, that reduces the annual revenue increases by the equivalent.
- All earnings in excess of 150 basis points over the OEB-approved return on equity will be shared equally between EGI and its ratepayers.

Our assessment of EGI's business risk reflects our view of the OEB's regulatory framework, which underpins the utility's predictable and steady cash flow. In our view, the regulatory process is transparent, consistent, and predictable. These factors collectively support EGI's timely recovery of prudently spent capital and operating expenses. In addition, commodity costs are recovered through a quarterly adjustment mechanism from rate-payers, limiting EGI's exposure to commodity risk.

Further supporting our view is EGI's large customer base. EGI serves almost all of Ontario's gas distribution network with about 3.7 million of customers, most of whom are residential and small business customers. As such, we expect EGI's cash flows to remain stable. However, demand for natural gas in the residential customer class can vary due to weather-driven fluctuations that can result in some cash flow volatility. Our favorable view of EGI's business risk is slightly offset by the company's limited geographic footprint and exposure to a single regulatory regime.

From a financial risk perspective, we assess EGI's cash flow using our low volatility leverage benchmarks compared with the typical corporate issuer, which reflects our favorable view of the company's lower-risk regulated gas distribution model and effective management of regulatory risk. Under our base-case scenario, including the revised terms of the amalgamation per the OEB, capital expenditure averaging about C$1 billion per year in 2019-2021, a dividend payment ratio reflecting 100% of EGI's operating cash flow, and synergies, we forecast average adjusted funds from operations (AFFO) to debt of about 12%-13% over the next two to three years.

Outlook

The stable outlook on Enbridge Gas Inc. (EGI) reflects S&P Global Ratings' expectation that the company will continue to focus on and generate stable and predictable cash flows from its regulated gas distribution operation. We also expect EGI will execute its integration plans from the amalgamation and capital programs on time and on budget leading to adjusted funds from operations (AFFO) to debt of about 12%-13% in 2019-2021.

The stable outlook also reflects our view that Enbridge Inc. (Enbridge), the parent, will maintain AFFO to debt in the 15%-18% range through 2020.

Furthermore, the stable outlook on EGI reflects our expectation that both the utility's insulation features and Enbridge's strategy to preserve the utilities' credit strength will not change.

Downside scenario

We could lower the ratings on EGI if the utility's financial measures deteriorate, with forecast AFFO to debt approaching 10% with no prospects of improvement. This could happen if the company experiences material operational issues, delays, and cost overruns in capital and post-amalgamation integration projects, or if adverse material regulatory decisions materially weaken the company's financial performance, or suggest a weaker business risk profile.

Alternatively, we could lower the rating on EGI if we lower our ratings on Enbridge. This could happen if Enbridge's consolidated AFFO to debt stays below 13% or debt to EBITDA remains above 5x in 2019 and beyond.

Upside scenario

A positive rating action on EGI is unlikely without an upgrade to Enbridge because our rating on EGI is constrained by the group credit profile of Enbridge, after accounting for an additional one notch of separation, since EGI is an insulated subsidiary of Enbridge. As such, we could upgrade EGI over the next 12 to 24 months if we upgrade Enbridge, and EGI's stand-alone credit profile (SACP) indicates a higher SACP. For EGI, a higher SACP could be warranted if EGI improves its financial measures with sustained AFFO to debt of about 13%, consistently. An upgrade at the Enbridge group level would require Enbridge to maintain AFFO to debt above 17% and adjusted debt to EBITDA of about 4x, while maintaining its current level of cash flow stability.

Company Description

Enbridge Gas Inc. (EGI) operates as a rate-regulated natural gas distribution utility company in Ontario, Canada. The company was formed through the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Ltd. The company also owns and operates regulated and non-regulated natural gas storage facilities in Ontario. EGI has a rate base of about C$10.5 billion and serves about 3.7 million customers.

Our Base-Case Scenario

- No significant cost overruns or delays in the post-amalgamation integration of EGD and Union.
- Capital expenditure of about C$1.0 billion per year in each of 2019-2021.
- Dividends payout ratio reflects 100% of EGI's cash flow from operations.
- EGI will earn close to its authorized return on equity.
- EGI will maintain its deemed capital structure of 64/36 debt to equity.
- Customer growth of about 1.0%-1.5% per year.
- Enbridge, the parent, or its affiliates will provide timely equity infusions to maintain EGI's deemed capital structure.
- Stable regulatory regime in Ontario, without any material, adverse regulatory decisions for EGI.
- Natural gas cost remains a pass through to rate-payers.

Liquidity

In our assessment, EGI's liquidity is adequate. We expect that liquidity sources will cover uses by more than 1.1x in the next 12 months. We also expect that in the event of a 10% EBITDA decline, the company's sources of funds would still exceed its uses. In our opinion, EGI has sound relationships with its banks and generally prudent financial risk management. In the event of unexpected financial stress, we believe the utility would scale back on its capital expenditures and has the flexibility to suspend dividend payments to preserve its liquidity.

Principal liquidity sources:

- Projected FFO of about C$1.25 billion;
- Committed credit facilities availability of about C$650 million (net of commercial paper backstop) maturing in 2020 and 2021; and
- Ongoing group cash injection of about C$800 million.

Principal liquidity uses:

- Capital spending of about C$1.2 billion over the next 12 months; and
- Dividends of about C$1.25 billion over the next 12 months.

Group Influence

We view EGI as an insulated subsidiary within the Enbridge group, reflecting our view that regulatory restrictions and the parent's strategy with respect to EGI will continue to preserve the utility's credit strength, consistent with our view of one-notch insulation for EGI. Specifically, the regulatory restrictions, inherited from EGD through the amalgamation, continue to limit EGI's business activities and requires the utility to maintain its common equity thickness at the regulatory deemed capital structure. This restriction, in our view, prevents EGI from supporting the Enbridge group in a manner that could impair its stand-alone creditworthiness.

Issue Ratings - Subordination Risk Analysis

Capital structure

As part of the amalgamation, EGI will assume all obligations, including senior unsecured debentures and outstanding credit facilities, of EGD and Union. The senior unsecured debt ranks pari passu with each other. We estimate a total of about C$9 billion of senior unsecured debentures in EGI's capital structure.

Analytical conclusions

We rate the senior unsecured debt at 'A-', the same as the issuer credit rating on EGI because the debt is issued by a qualifying investment-grade regulated utility per our criteria. The 'A-2' commercial paper rating reflects our issuer credit rating on the company, consistent with our criteria.

Ratings Score Snapshot

Issuer Credit Rating: A-/Stable/A-2

Business risk: Excellent
- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant
- Cash flow/Leverage: Significant

Anchor: a-

Modifiers
- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Financial policy: Neutral (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a-
- Group credit profile: bbb+
- Entity status within group: Insulated (no impact)

Related Criteria

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings , April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - Industrials: Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- General Criteria: Group Rating Methodology, Nov. 19, 2013

- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Ratings List

New Rating

Enbridge Gas Inc.	
Issuer Credit Rating	A-/Stable/A-2
Enbridge Gas Inc.	
Commercial Paper	A-1(LOW)
Commercial Paper	A-2

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

S&P Global
Ratings

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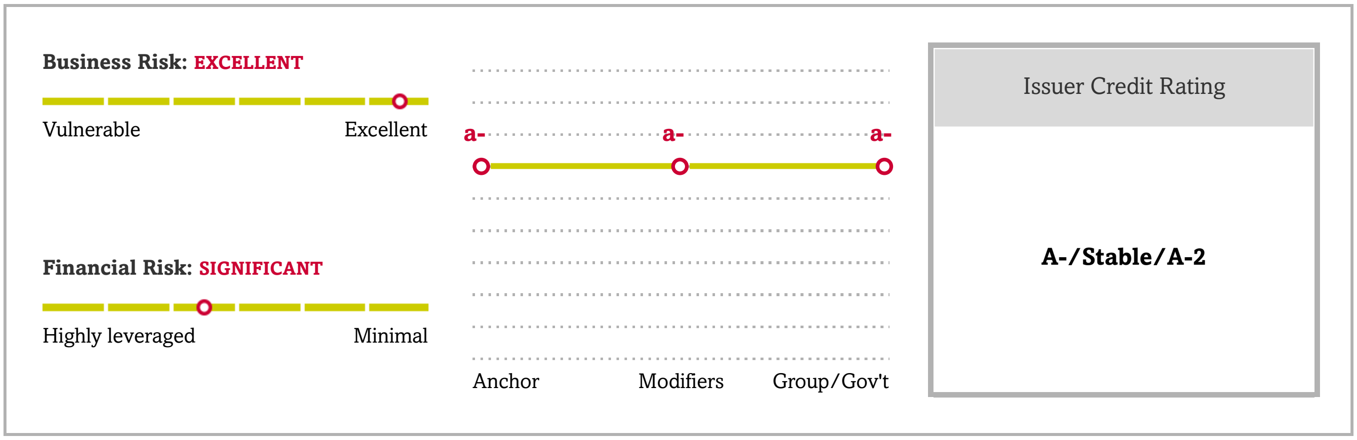
Enbridge Gas Inc.



Credit Highlights

Overview

Key strengths	Key risks
Enbridge Gas Inc. (EGI) is a low-risk rate-regulated natural gas distribution and transmission company.	EGI operates only in Ontario, hence limited geographic and regulatory diversification.
About two-thirds of EGI's distribution revenue comes from residential and small business customers, providing stable cash flows.	Negative discretionary cash flow, indicating external funding needs.
Commodity costs are pass through to customers and recovered through quarterly adjustment mechanism, limiting EGI's exposure to commodity risk.	

The OEB established deferral accounts to record costs and losses arising from the COVID-19 pandemic. On March 25, 2020, The Ontario Energy Board (OEB), regulator of Ontario, acknowledges that utility distributors, including Enbridge Gas Inc. (EGI), may incur incremental costs related to the ongoing coronavirus pandemic. As a result, the OEB established deferral accounts for utilities, including EGI, to track any incremental costs and lost revenues related to the COVID-19 pandemic. This allows EGI to recover potential lost revenue, incremental expenses, or costs relating to bad debt expenses subject to OEB approval. The pandemic is likely to result in cash flow volatility and lag for EGI in the short-term but the deferral accounts provides a recovery mechanism for utilities.

EGI has sufficient liquidity sources to cover its uses over the next six-12 months. The utility has a C$2.0 billion credit facility, mostly undrawn, to backstop its commercial paper program. In addition, the company's long-term debt maturity is modest for 2020, with about C$400 million maturing in November 2020. Moreover, EGI recently issued about C$1.2 billion of long-term debt in late March. As a result, we expect EGI to have sufficient liquidity over the next six-12 months. Furthermore, we expect the utility to scale back on capital spending or dividends to the parent group if needed.

EGI lacks geographic and regulatory diversity.

EGI operates only in Ontario. It is the largest gas distributor in Ontario and serves virtually all of Ontario with approximately 3.8 million residential, commercial, and industrial customers. However, compared with other utilities, EGI lacks geographic and regulatory diversity, making it reliant on the OEB to sustain its credit quality.

Outlook: Stable

The stable outlook on Enbridge Gas Inc. (EGI) reflects S&P Global Ratings' expectation that the company will continue to focus on and generate stable and predictable cash flows from its regulated gas distribution operation. We also expect EGI will execute its integration plans from the amalgamation and capital programs on time and on budget leading to funds from operations (FFO) to debt of about 11%-12% through 2021.

The stable outlook also reflects our view that Enbridge Inc. (Enbridge), the parent, will maintain FFO to debt in the 15%-18% range through 2021. Furthermore, the stable outlook on EGI reflects our expectation that both the utility's insulation features and Enbridge's strategy to preserve the utilities' credit strength will not change.

Downside scenario

We could lower the ratings on EGI if the utility's financial measures deteriorate, with FFO to debt approaching 10% with no prospects of improvement.

Alternatively, we could lower the rating on EGI if we lower our ratings on Enbridge. This could happen if Enbridge's consolidated adjusted FFO to debt stays below 13% or debt to EBITDA is sustained above 5x.

Upside scenario

Although unlikely, we can upgrade EGI over the next 18-24 months if we also upgrade Enbridge, and if EGI's stand-alone credit profile (SACP) indicates a higher SACP.

EGI could warrant a higher SACP if it improves its financial measures with FFO to debt consistently above 13%. An upgrade at the parent level would require Enbridge to maintain FFO to debt above 17% and adjusted debt to EBITDA of about 4x while maintaining its current level of cash flow stability.

Our Base-Case Scenario

Assumptions

- No material persistent impact from the COVID-19 pandemic.
- Stable regulatory regime in Ontario with no material adverse regulatory decisions.
- EGI will primarily operate under inflation-indexed rates through 2023, before starting a new rate application cycle in 2024.
- The annual revenue increases through 2023 will be

Key Metrics

	2019a	2020e	2021f
FFO to debt (%)	13.1	11-12	11-12
FFO cash interest coverage (x)	4.2	3.5-4.0	3.5-4.0

a--Actual. e--Estimate. f--Foremost. FFO--Funds from operations.

subject to a productivity stretch factor constraint of 0.3%, that reduces the annual revenue increases by the equivalent.

- All earnings in excess of 150 basis points over the OEB-approved return on equity will be shared equally between EGI and its ratepayers.
- EGI will earn close to its authorized return on equity.
- EGI will maintain its deemed capital structure of 64/36 debt to equity.
- Natural gas cost remains a pass through to rate-payers.
- Capital expenditure of about C$1.0 billion to C$1.5 billion per year in each of 2020-2022.
- Dividends payout ratio reflects about 100% of EGI's cash flow from operations.

Company Description

Enbridge Gas Inc. (EGI) operates as a rate-regulated natural gas distribution utility company in Ontario, Canada. The company was formed through the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Ltd. in 2019. The company also owns and operates regulated and nonregulated natural gas storage facilities in Ontario. EGI's distribution rates are set under a five-year incentive regulation framework using a price cap mechanism and it serves about 3.8 million customers.

Business Risk: Excellent

Our assessment of EGI's business risk continues to reflect our view of the OEB's regulatory framework, which underpins the utility's predictable and steady cash flow. In our view, the regulatory process is transparent, consistent, and predictable. These factors collectively support EGI's timely recovery of prudently spent capital and operating expenses. In addition, commodity costs are recovered through a quarterly adjustment mechanism from rate payers, limiting EGI's exposure to commodity risk.

Further supporting our view is EGI's large customer base. EGI serves almost all of Ontario's gas distribution network with about 3.8 million of customers, most of whom are residential and small business customers. As such, we expect EGI's cash flows to remain stable. However, demand for natural gas in the residential customer class can vary due to weather-driven fluctuations that can result in some cash flow volatility. Our favorable view of EGI's business risk is slightly offset by the company's limited geographic footprint and exposure to a single regulatory regime.

Peer comparison

Table 1

Enbridge Gas Inc. -- Peer Comparison

Industry Sector: Gas

	Enbridge Gas Inc.	CU Inc.	Energir Inc.	Alectra Inc.	Washington Gas Light Co.
Ratings as of March 31, 2020	A-/Stable/A-2	A-/Stable/A-2	A/Stable/--	A/Stable/--	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2019--	--Fiscal year ended Dec. 31, 2019--	--Fiscal year ended Sept. 30, 2019--	--Fiscal year ended Dec. 31, 2018--	--Fiscal year ended Sept. 30, 2018--
(Mil. Mix curr.)	C$	C$	C$	C$	$
Revenue	5,075.0	2,787.0	2,739.6	3,452.0	1,248.1
EBITDA	1,639.0	1,557.0	756.6	363.5	367.6
Funds from operations (FFO)	1,239.5	1,178.5	615.6	296.7	308.6
Interest expense	394.5	378.5	155.6	71.8	75.9
Cash interest paid	387.5	384.5	164.8	65.8	62.0
Cash flow from operations	1,277.5	1,155.5	687.3	235.7	123.1
Capital expenditure	1,104.0	936.0	627.0	425.0	392.8
Free operating cash flow (FOCF)	173.5	219.5	60.3	(189.3)	(269.7)
Discretionary cash flow (DCF)	(1,076.5)	(171)	(175.9)	(263.3)	(358.0)
Cash and short-term investments	77.0	71.0	101.3	16.0	0.0
Debt	9,435.1	8,136.8	4,268.1	2,016.3	1,497.5
Equity	10,004.0	4,853.0	2,346.9	1,689.0	1,456.9
Adjusted ratios					
EBITDA margin (%)	32.3	55.9	27.6	10.5	29.5
Return on capital (%)	5.3	8.4	6.3	6.2	6.9
EBITDA interest coverage (x)	4.2	4.1	4.9	5.1	4.8
FFO cash interest coverage (x)	4.2	4.1	4.7	5.5	6.0
Debt/EBITDA (x)	5.8	5.2	5.6	5.5	4.1
FFO/debt (%)	13.1	14.5	14.4	14.7	20.6
Cash flow from operations/debt (%)	13.5	14.2	16.1	11.7	8.2
FOCF/debt (%)	1.8	2.7	1.4	(9.4)	(18.0)
DCF/debt (%)	(11.4)	(2.1)	(4.1)	(13.1)	(23.9)

Sources: S&P Global Ratings, company data.

Financial Risk: Significant

We assess EGI's financial measures using our low volatility financial benchmark table relative to the typical industrial issuer. This reflects the company's lower-risk regulated gas distribution operation and effective management of regulatory risk. EGI has a large capital program--about 1.65x that of depreciation expense--that will result in negative discretionary cash flow and continually rely on external financing to fund its capital programs.

In respond to the current coronavirus pandemic, the OEB has setup deferral accounts for utilities, including EGI, to track incremental costs and lost revenues related to the pandemic for later disposition, subject to OEB review and approval. As a result, we expect there will be some cash flow volatility associated with EGI's financial measures for 2020.

Under our base case scenario that includes a short-term impact from the pandemic and a stable regulatory environment with no material adverse regulatory decisions, capital spending of about C$1.0 billion to C$1.5 billion in each of 2020 and 2021, and net dividend payments of about C$450 million annually, we expect EGI's FFO to debt to be about 11%-12% in 2020 and 2021.

Financial summary

Table 2

Enbridge Gas Inc. -- Financial Summary		
Industry Sector: Gas		
	--Fiscal year ended Dec. 31--	
	2019	2018
(Mil. C$)		
Revenue	5,075.0	5,297.0
EBITDA	1,639.0	1,551.0
Funds from operations (FFO)	1,239.5	1,190.0
Interest expense	394.5	391.0
Cash interest paid	387.5	394.0
Cash flow from operations	1,277.5	1,725.0
Capital expenditure	1,104.0	1,288.0
Free operating cash flow (FOCF)	173.5	437.0
Discretionary cash flow (DCF)	(1,076.5)	(996.0)
Cash and short-term investments	77.0	17.0
Gross available cash	77.0	17.0
Debt	9,435.1	9,120.6
Equity	10,004.0	9,893.0
Adjusted ratios		
EBITDA margin (%)	32.3	29.3
Return on capital (%)	5.3	7.5
EBITDA interest coverage (x)	4.2	4.0
FFO cash interest coverage (x)	4.2	4.0
Debt/EBITDA (x)	5.8	5.9
FFO/debt (%)	13.1	13.0
Cash flow from operations/debt (%)	13.5	18.9
FOCF/debt (%)	1.8	4.8
DCF/debt (%)	(11.4)	(10.9)

Sources: S&P Global Ratings, company data.

Liquidity: Adequate

In our assessment, EGI's liquidity is adequate. We expect that liquidity sources will cover uses by more than 1.1x in the next 12 months. We also expect that in the event of a 10% EBITDA decline, the company's sources of funds would still exceed its uses. In our opinion, EGI has solid relationships with its banks and generally prudent financial risk management. In the event of unexpected financial stress, we believe the utility would scale back on its capital expenditures and has the flexibility to suspend dividend payments to preserve its liquidity.

Principal Liquidity Sources	Principal Liquidity Uses
• Cash of about C$77 million as of Dec. 31, 2019; and • Committed credit facilities availability of about C$2 billion; and • Cash FFO of about C$1.2 billion	• Debt maturities of about C$1.3 billion as of Dec. 31, 2019, including current portion of long-term debt and outstanding commercial paper; and • Capital spending of about C$1.1 billion; and • Dividends of about C$450 million, net of ongoing group support.

Debt maturities

- 2020: C$400 million
- 2021: C$375 million
- 2022: C$125 million
- 2023: C$350 million
- 2024: C$300 million

Environmental, Social, And Governance

We view EGI's exposure to environmental, social, and governance-related risks as similar to the broader industry. EGI is a natural gas distributor. For natural gas network operators, environmental risks include gas leaks and explosions and emission of greenhouse gases (GHG), which can affect biodiversity. We believe EGI's environmental risk is consistent with the broader industry because the company continually monitors and replaces aging infrastructure to reduce the potential of gas leaks and explosions. In addition, the company also participates in the federal government's carbon levy program, to offset its GHG footprint in its gas distribution operations.

From a social perspective, EGI has a history of providing safe and reliable natural gas to its customers, which should enable it to maintain social cohesion. Governance factors are neutral. In our view, EGI's board is capably engaged in risk oversight on behalf of all stakeholders.

Group Influence

We view EGI as an insulated subsidiary within the Enbridge group. Specifically reflecting our views that EGI is incorporated as separate legal entities with financial performance and funding that are highly independent from the group, including issuing long- and short-term debt, maintaining its own separate credit facilities, and not commingling its funds, assets, or cash flows with the rest of the group. In addition, there is a strong economic basis for Enbridge to preserve EGI's credit strength, and we do not expect a default of the other group entities within Enbridge to directly lead to a default at EGI.

Issue Ratings - Subordination Risk Analysis

Capital structure

As of Dec. 31, 2019, EGI's capital structure consists of about C$900 million of short-term debt in commercial paper and about C$8.2 billion of senior unsecured long-term debt.

Analytical conclusions

We rate EGI's senior unsecured debt at 'A-', the same as the issuer credit rating (ICR) on EGI because the debt is issued by a qualifying investment-grade regulated utility. The rating on the commercial paper is 'A-2' reflecting our 'A-' ICR on EGI.

Reconciliation

Table 3

Reconciliation Of Enbridge Gas Inc. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2019--						
Enbridge Gas Inc. reported amounts							
	Debt	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	9,763.0	1,632.0	994.0	388.0	1,639.0	1,277.0	1,109.0
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(12.0)	--	--
Cash taxes paid: Other	--	--	--	--	--	--	--
Cash interest paid	--	--	--	--	(381.0)	--	--
Reported lease liabilities	46.0	--	--	--	--	--	--
Operating leases	--	7.0	1.5	1.5	(1.5)	5.5	--
Postretirement benefit obligations/deferred compensation	334.1	--	--	--	--	--	--
Accessible cash and liquid investments	(77.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	5.0	(5.0)	(5.0)	(5.0)

Table 3

Reconciliation Of Enbridge Gas Inc. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. C$) (cont.)

Nonoperating income (expense)	--	--	30.0	--	--	--	--
Debt: Other	(631.0)	--	--	--	--	--	--
Total adjustments	(328.0)	7.0	31.5	6.5	(399.5)	0.5	(5.0)

S&P Global Ratings' adjusted amounts

	Debt	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Capital expenditure
	9,435.1	1,639.0	1,025.5	394.5	1,239.5	1,277.5	1,104.0

Sources: S&P Global Ratings, company data.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral
- **Liquidity:** Adequate
- **Management and governance:** Satisfactory
- **Comparable rating analysis:** Neutral

Stand-alone credit profile : a-

- **Group credit profile:** bbb+
- **Entity status within group:** Insulated (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
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- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of April 3, 2020)*

Enbridge Gas Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	A-
Issuer Credit Ratings History	
02-Jan-2019	A-/Stable/A-2
Related Entities	
Enbridge Energy L.P.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+

Ratings Detail (As Of April 3, 2020)*(cont.)	
Enbridge Energy Partners L.P.	
Issuer Credit Rating	BBB+/Stable/NR
Senior Unsecured	BBB+
Enbridge Inc.	
Issuer Credit Rating	
Foreign Currency	BBB+/Stable/A-2
Local Currency	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Preferred Stock	
Canada National Scale Preferred Share	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+
Subordinated	BBB-
Enbridge Pipelines Inc.	
Issuer Credit Rating	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	BBB+
Spectra Energy Capital LLC	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Spectra Energy Corp	
Issuer Credit Rating	BBB+/Stable/--
Spectra Energy Partners LP	
Issuer Credit Rating	BBB+/Stable/NR
Senior Unsecured	BBB+
Texas Eastern Transmission L.P.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Westcoast Energy Inc.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock	
Canada National Scale Preferred Share	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

S&P Global
Ratings

Research

Enbridge Gas Inc.

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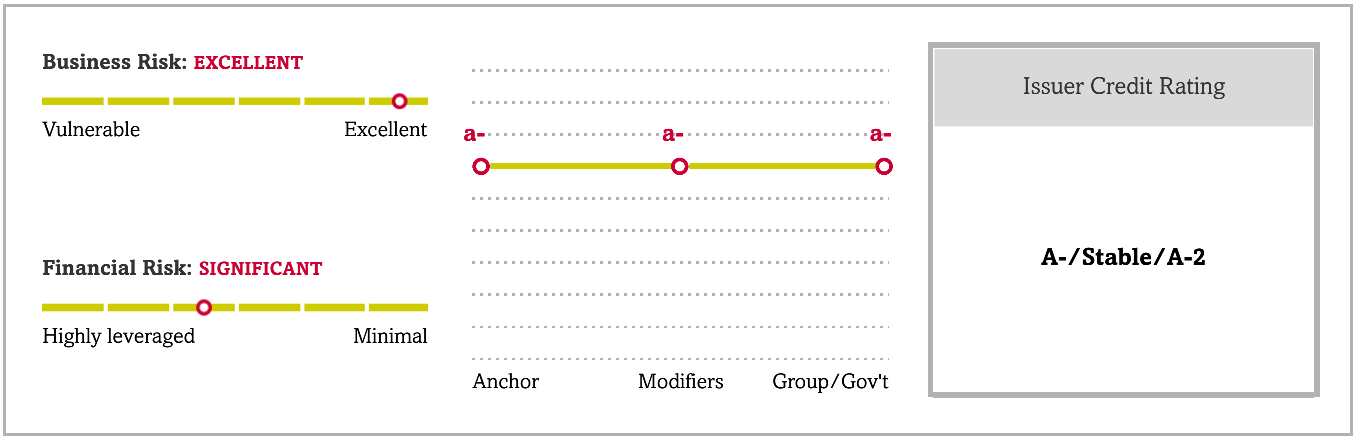
Enbridge Gas Inc.



Credit Highlights

Overview

Key strengths	Key risks
Enbridge Gas Inc. (EGI) is a low-risk rate-regulated natural gas distribution and transmission company.	EGI operates only in Ontario, hence limited geographic and regulatory diversification.
About two-thirds of EGI's distribution revenue comes from residential and small business customers, providing stable cash flows.	Negative discretionary cash flow, indicating external funding needs.
Commodity costs are passed through to customers and recovered through quarterly adjustment mechanism, limiting EGI's exposure to commodity risk.	

COVID-19 has had a modest impact on EGI's operations and cash flow so far. We don't expect the pandemic to have a persistent material effect on Enbridge Gas Inc.'s (EGI's) financial measures. EGI's financial performance has been in line with our expectation with funds from operation (FFO) to debt of about 11% for the 12 months ending Sept. 30, 2020. In addition, in March 2020, EGI's regulator, Ontario Energy Board (OEB), established deferral accounts for utilities to track incremental costs and lost revenues related to COVID-19. This allows EGI to potentially recover lost revenue, incremental expenses, or costs relating to bad debt expenses subject to OEB approval but is likely to result in cash flow volatility and lag for EGI in the short term. In addition, decrease in gas consumption from large commercial and industrial customers as a result of the pandemic is partially offset by increase in consumption from the higher margin residential segment. Furthermore, the company's synergies realization from the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Limited in 2019 also help to support financial measures.

Large capital spending plan over the outlook period. EGI continues to have large capital expenditures through the 2021-2022 outlook period that is about 1.8x its depreciation cost, which could pressure credit metrics and can lead to higher execution risks, including completing its key capital projects on time and within its budget.

EGI lacks geographic and regulatory diversity. EGI operates only in Ontario. It is the largest gas distributor in Ontario and serves virtually all of Ontario with approximately 3.8 million residential, commercial, and industrial customers. However, compared with other utilities, EGI lacks geographic and regulatory diversity, making it reliant on the OEB to sustain its credit quality.

Outlook

The stable outlook on EGI reflects S&P Global Ratings' expectation that the company will continue to focus on and generate stable and predictable cash flows from its regulated gas distribution operation. We also expect EGI will execute its integration plans from the amalgamation and capital programs on time and on budget leading to FFO to debt of about 11%-12% during our two-year outlook period.

The stable outlook also reflects our view that Enbridge Inc. (Enbridge), the parent, will maintain FFO to debt in the 15%-17% range through 2022. Furthermore, the stable outlook on EGI reflects our expectation that both the utility's insulation features and Enbridge's strategy to preserve the utilities' credit strength will not change.

Downside scenario

We could lower the ratings on EGI if the utility's financial measures deteriorate, with FFO to debt approaching 10% with no prospects of improvement.

Alternatively, we could lower the rating on EGI if we lower our ratings on Enbridge. This could happen if Enbridge's consolidated adjusted FFO to debt stays below 13% or debt to EBITDA is sustained above 5x.

Upside scenario

Although unlikely, we can upgrade EGI over the next 18-24 months if we also upgrade Enbridge, and if EGI's stand-alone credit profile (SACP) indicates a higher SACP.

EGI could warrant a higher SACP if it improves its financial measures with FFO to debt consistently above 13%. An upgrade at the parent level would require Enbridge to maintain FFO to debt above 17% and adjusted debt to EBITDA of about 4x while maintaining its current level of asset mix and cash-flow stability.

Our Base-Case Scenario

Assumptions

- No material persistent impact from the COVID-19 pandemic.
- Stable regulatory regime in Ontario with no material adverse regulatory decisions.
- EGI will primarily operate under inflation-indexed rates through 2023, before starting a new rate application cycle in 2024.
- The annual revenue increases through 2023 will be subject to a productivity stretch factor constraint of 0.3%, that reduces the annual revenue increases by the equivalent amount.
- All earnings in excess of 150 basis points over the OEB-approved return on equity will be shared equally between EGI and its ratepayers.
- EGI will earn close to its authorized return on equity.
- EGI will maintain its deemed capital structure of 64%/36% debt to equity.
- Natural gas cost and the federal carbon levy remain a pass through to ratepayers.

- Capital expenditure of about C$1.1 billion-C$1.6 billion in each of 2020 and 2022.
- Dividends of about C$450 million in 2020 and C$200 million in each of 2021 and 2022.

Key Metrics

	2019a	2020e	2021f
FFO to debt (%)	13.1	11-12	11-12
FFO cash interest coverage (x)	4.2	3.5-4.0	3.5-4.0

a--Actual. e--Estimate. f--Foremost. FFO--Funds from operations.

Company Description

EGI operates as a rate-regulated natural gas distribution utility company in Ontario, Canada. The company was formed through the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Ltd. in 2019. The company also owns and operates regulated and nonregulated natural gas storage facilities in Ontario. EGI's distribution rates are set under a five-year incentive regulation framework using a price cap mechanism and it serves about 3.8 million customers.

Peer comparison

Table 1

Enbridge Gas Inc.--Peer Comparison

Industry Sector: Gas

	Enbridge Gas Inc.	CU Inc.	Energir Inc.	Washington Gas Light Co.
Ratings as of Jan. 11, 2021	A-/Stable/A-2	A-/Stable/A-2	A/Stable	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2019--	--Fiscal year ended Dec. 31, 2019--	--Fiscal year ended Sept. 30, 2020--	--Fiscal year ended Dec. 31, 2019--
(Mil. Mix curr.)	C$	C$	C$	$
Revenue	5,075.0	2,787.0	2,569.3	1,330.7
EBITDA	1,639.0	1,557.0	786.4	333.5
Funds from operations (FFO)	1,239.5	1,178.5	685.4	254.3
Interest expense	394.5	389.7	163.5	75.3
Cash interest paid	387.5	384.5	163.8	63.6
Cash flow from operations	1,277.5	1,155.5	278.2	202.8
Capital expenditure	1,104.0	936.0	680.3	433.0
Free operating cash flow (FOCF)	173.5	219.5	(402.1)	(230.1)
Discretionary cash flow (DCF)	(1,076.5)	(171.0)	(872.4)	(359.0)
Cash and short-term investments	77.0	71.0	153.7	17.1
Debt	9,435.1	8,371.4	4,702.1	1,852.0
Equity	10,004.0	4,853.0	2,169.8	1,572.2

Table 1

Enbridge Gas Inc.--Peer Comparison (cont.)

Adjusted ratios				
EBITDA margin (%)	32.3	55.9	30.6	25.1
Return on capital (%)	5.3	8.3	6.4	5.5
EBITDA interest coverage (x)	4.2	4.0	4.8	4.4
FFO cash interest coverage (x)	4.2	4.1	5.2	5.0
Debt/EBITDA (x)	5.8	5.4	6.0	5.6
FFO/debt (%)	13.1	14.1	14.6	13.7
Cash flow from operations/debt (%)	13.5	13.8	5.9	11.0
FOCF/debt (%)	1.8	2.6	(8.6)	(12.4)
DCF/debt (%)	(11.4)	(2.0)	(18.6)	(19.4)

Business Risk

Our assessment of EGI's business risk continues to reflect our view of the OEB's regulatory framework, which underpins the utility's predictable and steady cash flow. In our view, the regulatory process is transparent, consistent, and predictable. These factors collectively support EGI's timely recovery of prudently spent capital and operating expenses. In addition, the federal carbon levy is a flow through cost to customers and gas commodity costs are recovered through a quarterly adjustment mechanism from ratepayers, limiting EGI's exposure to commodity risk.

Further supporting our view is EGI's large customer base. EGI serves almost all of Ontario's gas distribution network with about 3.8 million of customers, most of whom are residential and small business customers. As such, we expect EGI's cash flows to remain stable. However, demand for natural gas in the residential customer class can vary due to weather-driven fluctuations that can result in some cash flow volatility. Our favorable view of EGI's business risk is slightly offset by the company's limited geographic footprint and exposure to a single regulatory regime.

Financial Risk

We assess EGI's financial measures using our low volatility financial benchmark table relative to the typical industrial issuer. This reflects the company's lower-risk regulated gas distribution operation and effective management of regulatory risk. EGI has a large capital program--about 1.8x that of depreciation expense--that will result in negative discretionary cash flow and continually rely on external financing to fund its capital programs.

In response to the coronavirus pandemic, the OEB set up deferral accounts for utilities in early 2020, including EGI, to track incremental costs and lost revenues related to the pandemic for later disposition, subject to OEB review and approval. As a result, we expect there will be some cash flow volatility associated with EGI's financial measures for 2020.

Under our base-case scenario that includes a short-term impact from the pandemic and a stable regulatory environment with no material adverse regulatory decisions, capital spending of about C$1.1 billion-C$1.6 billion in each of 2020 and 2022, and net dividend payments of about C$450 million in 2020 and about C$200 million in each of 2021 and 2022, we expect EGI's FFO to debt to be about 11%-12% in 2020 and 2022.

Financial summary

Table 2

Enbridge Gas Inc.--Financial Summary

Industry Sector: Gas

	--Fiscal year ended Dec. 31--		
	2019	**2018**	**2017**
(Mil. C$)			
Revenue	5,075.0	5,297.0	3,292.0
EBITDA	1,639.0	1,551.0	750.0
Funds from operations (FFO)	1,239.5	1,190.0	532.0
Interest expense	394.5	391.0	220.0
Cash interest paid	387.5	394.0	214.0
Cash flow from operations	1,277.5	1,725.0	558.0
Capital expenditure	1,104.0	1,288.0	794.0
Free operating cash flow (FOCF)	173.5	437.0	(236.0)
Discretionary cash flow (DCF)	(1,076.5)	(996.0)	(896.0)
Cash and short-term investments	77.0	17.0	20.0
Gross available cash	77.0	17.0	20.0
Debt	9,435.1	9,120.6	4,789.9
Equity	10,004.0	9,893.0	3,309.0
Adjusted ratios			
EBITDA margin (%)	32.3	29.3	22.8
Return on capital (%)	5.3	7.5	5.6
EBITDA interest coverage (x)	4.2	4.0	3.4
FFO cash interest coverage (x)	4.2	4.0	3.5
Debt/EBITDA (x)	5.8	5.9	6.4
FFO/debt (%)	13.1	13.0	11.1
Cash flow from operations/debt (%)	13.5	18.9	11.6
FOCF/debt (%)	1.8	4.8	(4.9)
DCF/debt (%)	(11.4)	(10.9)	(18.7)

Reconciliation

Table 3

Enbridge Gas Inc.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

	--Fiscal year ended Dec. 31, 2019--						
Enbridge Gas Inc. reported amounts (mil. C$)							
	Debt	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	9,763.0	1,632.0	994.0	388.0	1,639.0	1,277.0	1,109.0

Table 3

Enbridge Gas Inc.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts (cont.)

S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(12.0)	--	--
Cash interest paid	--	--	--	--	(381.0)	--	--
Reported lease liabilities	46.0	--	--	--	--	--	--
Operating leases	--	7.0	1.5	1.5	(1.5)	5.5	--
Postretirement benefit obligations/deferred compensation	334.1	--	--	--	--	--	--
Accessible cash and liquid investments	(77.0)	--	--	--	--	--	--
Capitalized interest	--	--	--	5.0	(5.0)	(5.0)	(5.0)
Nonoperating income (expense)	--	--	30.0	--	--	--	--
Debt: Other	(631.0)	--	--	--	--	--	--
Total adjustments	(328.0)	7.0	31.5	6.5	(399.5)	0.5	(5.0)

S&P Global Ratings' adjusted amounts

	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	9,435.1	1,639.0	1,025.5	394.5	1,239.5	1,277.5	1,104.0

Liquidity

In our assessment, EGI's liquidity is adequate. We expect liquidity sources will cover uses by more than 1.1x in the next 12 months. We also expect that in the event of a 10% EBITDA decline, the company's sources of funds would still exceed its uses. In our opinion, EGI has solid relationships with its banks and generally prudent financial risk management. In the event of unexpected financial stress, we believe the utility would scale back on its capital expenditures and has the flexibility to suspend dividend payments to preserve its liquidity.

Principal liquidity sources

- Cash of about C$10 million as of Sept. 30, 2020;
- Committed credit facilities availability of about C$2 billion; and
- Cash FFO of about C$1.2 billion.

Principal liquidity uses

- Debt maturities of about C$1.6 billion as of Sept. 30, 2020, including current portion of long-term debt and outstanding commercial paper;
- Maintenance capital spending of about C$370 million over the next 12 months; and
- Dividends of about C$260 million, net of ongoing group support.

Debt maturities

- 2021: C$375 million
- 2022: C$125 million
- 2023: C$350 million
- 2024: C$300 million

Environmental, Social, And Governance

We view EGI's exposure to environmental, social, and governance-related risks as similar to the broader industry. EGI is a natural gas utility distributor. For natural gas network operators, environmental risks include gas leaks and explosions and emission of greenhouse gases (GHG), which can affect biodiversity. We view EGI's environmental risk is consistent with the broader industry because the company continually monitors and replaces aging infrastructure to reduce the potential for gas leaks and explosions. In addition, the company also participates in the federal government's carbon levy program, to offset its GHG footprint in its gas distribution operations. Furthermore, the company recently launched a pilot initiative to blend renewable hydrogen gas into existing EGI natural gas network in an effort to reduce GHG.

From a social perspective, EGI has a history of providing safe and reliable natural gas to its customers, which should enable it to maintain social cohesion. Governance factors are neutral. In our view, EGI's board is capably engaged in risk oversight on behalf of all stakeholders.

Group Influence

We view EGI as an insulated subsidiary within the Enbridge group. Specifically reflecting our views that EGI is incorporated as separate legal entity with financial performance and funding that are highly independent from the group, including issuing long- and short-term debt, maintaining its own separate credit facilities, and not commingling its funds, assets, or cash flows with the rest of the group. In addition, there is a strong economic basis for Enbridge to preserve EGI's credit strength, and we do not expect a default of the other group entities within Enbridge to directly lead to a default at EGI.

Issue Ratings - Subordination Risk Analysis

Capital structure

As of Sept. 30, 2020, EGI's capital structure consists of about C$970 million of short-term debt, including outstanding commercial paper and about C$9.4 billion of senior unsecured long-term debt.

Analytical conclusions

We rate EGI's senior unsecured debt at 'A-', the same as the issuer credit rating (ICR) on EGI because the debt is issued by a qualifying investment-grade regulated utility. The rating on the commercial paper is 'A-2' reflecting our 'A-' ICR on EGI.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/portfolio effect:** Neutral
- **Capital structure:** Neutral
- **Financial policy:** Neutral
- **Liquidity:** Adequate
- **Management and governance:** Satisfactory
- **Comparable rating analysis:** Neutral

Stand-alone credit profile : a-

- **Group credit profile:** bbb+
- **Entity status within group:** Insulated (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013

- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of January 19, 2021)*

Enbridge Gas Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	A-
Issuer Credit Ratings History	
02-Jan-2019	A-/Stable/A-2
Related Entities	
Enbridge Energy L.P.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Enbridge Energy Partners L.P.	
Issuer Credit Rating	BBB+/Stable/NR
Senior Unsecured	BBB+
Enbridge Inc.	
Issuer Credit Rating	
Foreign Currency	BBB+/Stable/A-2
Local Currency	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Preferred Stock *Canada National Scale Preferred Share*	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+
Subordinated	BBB-
Enbridge Pipelines Inc.	
Issuer Credit Rating	BBB+/Stable/--

Ratings Detail (As Of January 19, 2021)*(cont.)	
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	BBB+
Spectra Energy Capital LLC	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Spectra Energy Corp	
Issuer Credit Rating	BBB+/Stable/--
Spectra Energy Partners LP	
Issuer Credit Rating	BBB+/Stable/NR
Senior Unsecured	BBB+
Texas Eastern Transmission L.P.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Westcoast Energy Inc.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock *Canada National Scale Preferred Share*	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

S&P Global
Ratings

Research

Enbridge Gas Inc.

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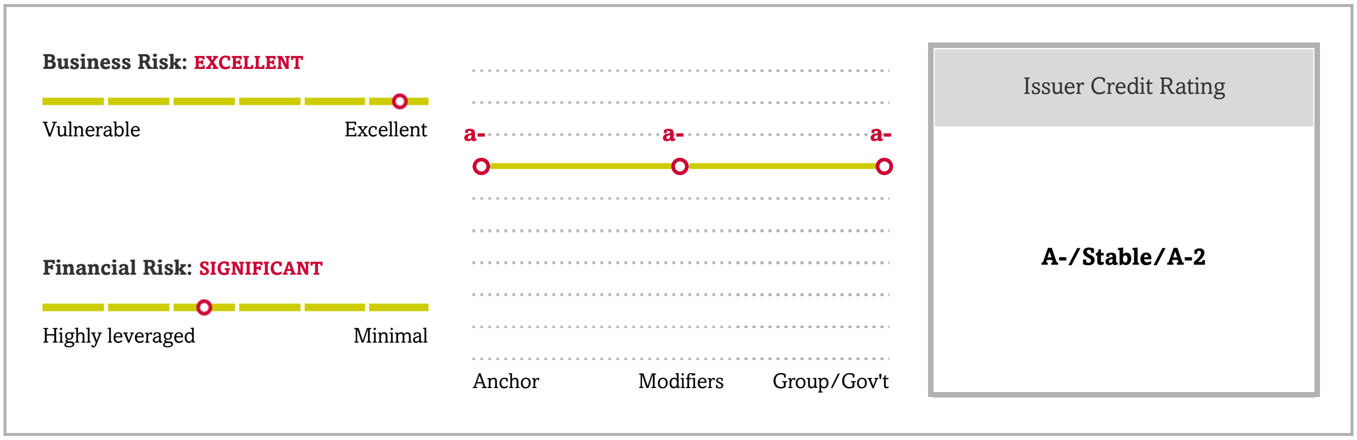
Enbridge Gas Inc.



Credit Highlights

Overview

Key strengths	Key risks
Enbridge Gas Inc. (EGI) is a low-risk, rate-regulated natural gas distribution and transmission company.	EGI operates only in Ontario and therefore has limited geographic and regulatory diversification.
About two-thirds of EGI's distribution revenue comes from residential and small business customers, providing stable cash flows.	EGI has negative discretionary cash flow linked with increasing capital expenditure activities, indicating external funding needs.
Commodity costs are passed through to customers and recovered through a quarterly adjustment mechanism, limiting EGI's exposure to commodity risk.	

We expect EGI's financial measures to remain within its financial risk profile category through 2023. This includes a projected funds from operations (FFO) to debt ratio of about 11% through 2023. In addition, we anticipate EGI's capital expenditures to remain elevated during 2022, largely reflecting new customer connections and system replacement projects such as the Lake Shore and St. Laurent natural gas pipeline replacement projects.

Additionally, as in prior years, we expect in 2022 EGI will realize positive synergies from the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Ltd. (Union Gas), by continuing to integrate operations and optimizing storage and transmission assets.

Large capital spending primarily results in negative discretionary cash flow over our outlook period. EGI continues to have large capital expenditures through the 2022-2023 outlook period. They are about 2x its depreciation cost, which we expect will lead to negative discretionary cash flow over our forecast period, resulting in external funding needs.

EGI lacks geographic and regulatory diversity. EGI operates only in Ontario. It is the largest gas distributor in Ontario and serves virtually all of Ontario with approximately 3.8 million residential, commercial, and industrial customers. However, compared with other utilities, EGI lacks geographic and regulatory diversity, making it reliant on the Ontario Energy Board (OEB) and its regulation to sustain its credit quality.

Outlook

The stable outlook on EGI reflects S&P Global Ratings' expectation that the company will continue to focus on and generate stable and predictable cash flows from its regulated gas distribution operation. We expect that EGI will continue to benefit from modest growth in new customers, the integration of EGD and Union Gas operations and assets, and the timely and on-budget completion of capital programs. This leads to estimated FFO to debt of 11%-12% during our two-year outlook period.

The stable outlook also reflects our view that Enbridge Inc. (Enbridge), the parent, will maintain FFO to debt of 15%-17% in 2022. Furthermore, the stable outlook on EGI reflects our expectation that both the utility's insulation features and Enbridge's strategy to preserve the utilities' credit strength will not change.

Downside scenario

We could lower the ratings on EGI if the utility's financial measures deteriorate, with FFO to debt approaching 10% with no prospects of improvement.

Alternatively, we could lower the ratings on EGI if we lower our ratings on Enbridge. This could happen if Enbridge's consolidated adjusted FFO to debt falls below 13% or debt to EBITDA is sustained above 5x.

Upside scenario

Although unlikely, we could upgrade EGI over the next 18-24 months if we also upgrade Enbridge, and if EGI's stand-alone credit profile (SACP) indicates a higher SACP.

EGI could warrant a higher SACP if it improves its financial measures with FFO to debt consistently above 13%. An upgrade at the parent level would require Enbridge to maintain FFO to debt above 17% and adjusted debt to EBITDA of about 4x while maintaining its current level of asset mix and cash-flow stability.

Our Base-Case Scenario

Assumptions

- Stable and predictable cash flows from its regulated gas distribution operation, also benefiting from modest new customer growth.
- Stable regulatory regime in Ontario with no material adverse regulatory decisions.
- EGI will primarily operate under inflation-indexed rates throughout 2022 and 2023, before starting a new rate application cycle in 2024.
- The annual revenue increases through 2023 will be subject to a productivity stretch factor constraint of 0.3%, which reduces the annual revenue increases by the equivalent amount.
- All earnings exceeding 150 basis points over the OEB-approved return on equity will be shared equally between EGI and its ratepayers.
- EGI will earn close to its authorized return on equity.
- EGI will operate at or close to its authorized capital structure of 64%/36% debt to equity for the duration of the

outlook period.

- Natural gas cost and the federal carbon levy remain a pass-through to ratepayers.
- Annual capital expenditure estimated to be about C$1.4 billion to C$1.6 billion between 2022 and 2024.
- Dividends of about C$200 million in 2021 and estimated to range from C$525 to C$575 million in each of 2022, 2023, and 2024.

Key metrics

	--Fiscal year end Dec. 31 --			
	2019a	**2020a**	**2021e**	**2022f**
FFO to debt (%)	13.1	11.3	11-12	11-12
FFO cash interest coverage (x)	4.2	3.9	4.0-4.5	4.0-4.5

*All figures adjusted by S&P Global Ratings. a--Actual. e--Estimate. f--Forecast.

Company Description

EGI operates as a rate-regulated natural gas distribution utility company in Ontario, Canada. The company was formed through the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Ltd. in 2019. The company also owns and operates regulated and nonregulated natural gas storage facilities in Ontario. EGI's distribution rates are set under a five-year incentive regulation framework using a price cap mechanism, and it serves about 3.8 million customers.

Peer Comparison

Table 1

Enbridge Gas Inc.--Peer Comparison

Industry Sector: Gas

	Enbridge Gas Inc.	**CU Inc.**	**Energir Inc.**	**Washington Gas Light Co.**
Ratings as of Jan. 24, 2022	A-/Stable/A-2	A-/Stable/A-2	--/--/--	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2020--	**--Fiscal year ended Dec. 31, 2020--**	**--Fiscal year ended Sep. 30, 2021--**	**--Fiscal year ended Dec. 31, 2020--**
(Mil.)	**C$**	**C$**	**C$**	**$**
Revenue	4,515.0	2,730.0	2,434.2	1,234.3
EBITDA	1,575.0	1,421.0	796.9	370.7
Funds from operations (FFO)	1,117.5	1,045.5	577.5	307.6
Interest expense	404.5	389.7	145.6	76.0
Cash interest paid	391.5	376.5	143.7	66.0
Cash flow from operations	1,204.5	1,058.5	438.8	226.9
Capital expenditure	1,180.0	782.0	581.5	389.8
Free operating cash flow (FOCF)	24.5	276.5	(142.7)	(162.9)

Table 1

Enbridge Gas Inc.--Peer Comparison (cont.)				
Discretionary cash flow (DCF)	(1,225.5)	(149)	(668.2)	(262.9)
Cash and short-term investments	9.0	78.0	46.8	0.0
Debt	9,912.2	8,516.9	4,178.8	1,899.8
Equity	10,017.0	4,816.0	2,151.5	1,855.9
Adjusted ratios				
EBITDA margin (%)	34.9	52.1	32.7	30.0
Return on capital (%)	4.7	6.8	6.1	6.0
EBITDA interest coverage (x)	3.9	3.6	5.5	4.9
FFO cash interest coverage (x)	3.9	3.8	5.0	5.7
Debt/EBITDA (x)	6.3	6.0	5.2	5.1
FFO/debt (%)	11.3	12.3	13.8	16.2
Cash flow from operations/debt (%)	12.2	12.4	10.5	11.9
FOCF/debt (%)	0.2	3.2	(3.4)	(8.6)
DCF/debt (%)	(12.4)	(1.7)	(16.0)	(13.8)

N.M.--Not meaningful

Business Risk

Our assessment of EGI's business risk reflects our view of OEB's regulatory framework, which underpins the utility's predictable and steady cash flow. In our view, the regulatory process is transparent, consistent, and predictable. These factors collectively support EGI's timely recovery of prudently spent capital and operating expenses. In addition, the federal carbon levy is a flow-through cost to customers, and gas commodity costs are recovered through a quarterly adjustment mechanism from ratepayers, limiting EGI's exposure to commodity risk.

Further supporting our view is EGI's large customer base. EGI serves almost all of Ontario's gas distribution network with about 3.8 million customers, most of whom are residential and small business customers. As such, we expect EGI's cash flows to remain stable. However, demand for natural gas in the residential customer class can vary due to weather-driven fluctuations that can result in some cash flow volatility. Our favorable view of EGI's business risk is slightly offset by the company's limited geographic footprint and exposure to a single regulatory regime.

Financial Risk

We assess EGI's financial measures using our low volatility financial benchmark table relative to the typical industrial issuer. This reflects the company's lower-risk regulated gas distribution operation and effective management of regulatory risk. EGI has a large capital program--about 2x that of depreciation expense--that will result in negative discretionary cash flow and continually rely on external financing to fund its capital programs.

Under our base-case scenario, which includes a stable regulatory environment with no material adverse regulatory decisions, we expect capital spending of about C$1.3 billion-C$1.6 billion through 2022; net dividend payments of about C$200 million in 2021 and C$500-C$550 million in 2022 and 2023; and FFO to debt of about 11%-12% between 2021 and 2023.

Financial summary

Table 2

Enbridge Gas Inc.--Financial Summary

Industry Sector: Gas

	--Fiscal year ended Dec. 31--			
	2020	**2019**	**2018**	**2017**
(Mil. C$)				
Revenue	4,515.0	5,075.0	5,297.0	3,292.0
EBITDA	1,575.0	1,639.0	1,551.0	750.0
Funds from operations (FFO)	1,117.5	1,239.5	1,190.0	532.0
Interest expense	404.5	394.5	391.0	220.0
Cash interest paid	391.5	387.5	394.0	214.0
Cash flow from operations	1,204.5	1,277.5	1,725.0	558.0
Capital expenditure	1,180.0	1,104.0	1,288.0	794.0
Free operating cash flow (FOCF)	24.5	173.5	437.0	(236)
Discretionary cash flow (DCF)	(1,225.5)	(1,076.5)	(996.0)	(896)
Cash and short-term investments	9.0	77.0	17.0	20.0
Gross available cash	9.0	77.0	17.0	20.0
Debt	9,912.2	9,435.1	9,120.6	4,789.9
Equity	10,017.0	10,004.0	9,893.0	3,309.0
Adjusted ratios				
EBITDA margin (%)	34.9	32.3	29.3	22.8
Return on capital (%)	4.7	5.3	7.5	5.6
EBITDA interest coverage (x)	3.9	4.2	4.0	3.4
FFO cash interest coverage (x)	3.9	4.2	4.0	3.5
Debt/EBITDA (x)	6.3	5.8	5.9	6.4
FFO/debt (%)	11.3	13.1	13.0	11.1
Cash flow from operations/debt (%)	12.2	13.5	18.9	11.6
FOCF/debt (%)	0.2	1.8	4.8	(4.9)
DCF/debt (%)	(12.4)	(11.4)	(10.9)	(18.7)

N.M.--Not meaningful

Reconciliation

Table 3

Enbridge Gas Inc.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

	--Fiscal year ended Dec. 31, 2020--						
Enbridge Gas Inc. reported amounts (mil. C$)							
	Debt	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	10,103	1,566	911	398	1,575	1,202	1,185
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(66.00)	--	--
Cash interest paid	--	--	--	--	(385.00)	--	--
Reported lease liabilities	53.00	--	--	--	--	--	--
Operating leases	--	9.00	1.53	1.53	(1.53)	7.47	--
Postretirement benefit obligations/deferred compensation	424.15	--	--	--	--	--	--
Accessible cash and liquid investments	(9.00)	--	--	--	--	--	--
Capitalized interest	--	--	--	5.00	(5.00)	(5.00)	(5.00)
Nonoperating income (expense)	--	--	11.00	--	--	--	--
Debt: Other	(659.00)	--	--	--	--	--	--
Total adjustments	(190.85)	9.00	12.53	6.53	(457.53)	2.47	(5.00)
S&P Global Ratings' adjusted amounts							
	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	9,912	1,575	924	405	1,117	1,204	1,180

Liquidity

In our assessment, EGI's liquidity is adequate. We expect liquidity sources will cover uses by more than 1.1x in the next 12 months. We also expect that in the event of a 10% EBITDA decline, the company's sources of funds would still exceed its uses. In our opinion, EGI has strong relationships with its banks and generally prudent financial risk management. In the event of unexpected financial stress, we believe the utility would scale back on its capital expenditures and has the flexibility to suspend dividend payments to preserve its liquidity.

Principal liquidity sources

- Cash of about C$8 million as of Sept. 30, 2021;
- Committed credit facilities availability of about C$2 billion;
- Cash FFO of about C$1.2 billion; and
- Working capital inflows of about C$31 million.

Principal liquidity uses

- Debt maturities of about C$1.51 billion as of Sept. 30, 2021;
- Assumed maintenance capital spending of about C$1.0 billion over the next 12 months; and
- Net dividends of about C$444 million.

Debt maturities

- 2022: C$125 million
- 2023: C$350 million
- 2024: C$300 million
- 2025: C$745 million

Environmental, Social, And Governance

ESG Credit Indicators

E-1	**E-2**	E-3	E-4	E-5	S-1	**S-2**	S-3	S-4	S-5	G-1	**G-2**	G-3	G-4	G-5

ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1-5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicators: Definition And Applications," published Oct. 13, 2021.

ESG factors have no material influence on our credit rating analysis of EGI.

Group Influence

We view EGI as an insulated subsidiary within the Enbridge group. This is because EGI is incorporated as separate legal entity with financial performance and funding that are highly independent from the group, including issuing long- and short-term debt, maintaining its own separate credit facilities, and not commingling its funds, assets, or cash flows with the rest of the group. In addition, there is a strong economic basis for Enbridge to preserve EGI's credit strength, and we do not expect a default of the other group entities within Enbridge to directly lead to a default at EGI.

Issue Ratings--Subordination Risk Analysis

Capital structure

As of Sept. 30, 2021, EGI's capital structure consists of about C$1.21 billion of short-term debt in outstanding commercial paper and about C$9.7 billion of senior unsecured long-term debt.

Analytical conclusions

We rate EGI's senior unsecured debt at 'A-', the same as the issuer credit rating (ICR) on EGI because the debt is issued by a qualifying investment-grade regulated utility. The rating on the commercial paper is 'A-2' reflecting our 'A-'

ICR on EGI.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** bbb+
- **Entity status within group:** Insulated (no impact)

Issuer Credit Rating: A-/Stable/A-2

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant

- Cash flow/Leverage: Significant

Anchor: a-

Modifiers

- Diversification/Portfolio effect: Neutral
- Capital structure: Neutral
- Financial policy: Neutral
- Liquidity: Adequate
- Management and governance: Satisfactory
- Comparable rating analysis: Neutral

Stand-alone credit profile: a-

- Group credit profile: bbb+
- Entity status within group: Insulated (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of February 1, 2022)*

Enbridge Gas Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	A-
Issuer Credit Ratings History	
02-Jan-2019	A-/Stable/A-2
Related Entities	
Enbridge Energy L.P.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Enbridge Energy Partners L.P.	
Issuer Credit Rating	BBB+/Stable/NR
Senior Unsecured	BBB+
Enbridge Inc.	
Issuer Credit Rating	
Foreign Currency	BBB+/Stable/A-2
Local Currency	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Preferred Stock *Canada National Scale Preferred Share*	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+
Subordinated	BBB-
Enbridge Pipelines Inc.	
Issuer Credit Rating	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	BBB+

Ratings Detail (As Of February 1, 2022)*(cont.)	
Spectra Energy Capital LLC	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Spectra Energy Corp.	
Issuer Credit Rating	BBB+/Stable/--
Spectra Energy Partners L.P.	
Issuer Credit Rating	BBB+/Stable/NR
Senior Unsecured	BBB+
Texas Eastern Transmission L.P.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Westcoast Energy Inc.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock *Canada National Scale Preferred Share*	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

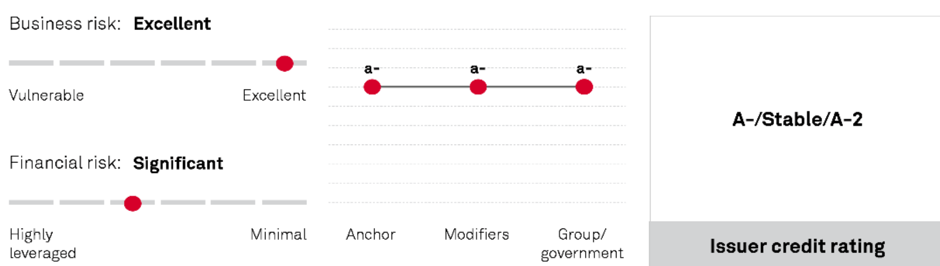
S&P Global
Ratings

Research

Enbridge Gas Inc.

July 21, 2022

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Low-risk, rate-regulated natural gas distribution and transmission company.	Operates only in Ontario, thus it has limited geographic and regulatory diversity.
Derives about two-thirds of its distribution revenue from residential and small business customers, which provide stable cash flows.	Negative discretionary cash flow due to increasing capital expenditure activities indicates external funding needs.
Passes commodity costs through to customers and recovers costs through a quarterly adjustment mechanism, which limits its exposure to commodity risk.	

*We expect **Enbridge Gas Inc.** (EGI) to maintain its financial performance throughout our two-year outlook period.* This includes projected funds from operations (FFO) to debt of about 11% and dividends of about C$200 million through 2024. In addition, we anticipate EGI's capital expenditure will remain elevated at about C$1.6 billion during 2022, which largely reflects new customer connections and system replacement projects, such as the Lake Shore and St. Laurent natural gas pipeline replacement projects. The company's large capital spending, totaling more than 2x its depreciation expense, will lead it to generate negative discretionary cash flow over our outlook period, which indicates a need for external funding.

EGI continues to operate in a credit supportive regulatory framework as the Ontario Energy Board (OEB) recently approved its requested capital funding for 2022. In April 2022, the OEB issued its decision on phase 2 of the company's 2022 Rate Application addressing incremental capital module funding requirements, under which it approved C$127 million of EGI's requested capital funding. The approved capital funding was incorporated into the company's final rates and became effective on July 1, 2022. Phase 1 of EGI's 2022 Rate Application was approved in late 2021 and addressed the inflation-indexed price rate mechanism increase of 1.4% for its 2022 consumer rates.

EGI lacks geographic and regulatory diversity. The company operates only in Ontario, is the largest gas distributor in Ontario, and serves virtually all of the province's approximately 3.8 million residential, commercial, and industrial customers. However, compared with other utilities, EGI lacks geographic and regulatory diversity, which makes it reliant on the OEB's regulation to sustain its credit quality.

Outlook

The stable outlook on EGI reflects our expectation that it will continue to focus on, and generate stable and predictable cash flows from, its regulated gas distribution operations. We also expect that the company will continue to benefit from modest growth in its new customers and the timely and on-budget completion of its capital programs. This leads us to forecast FFO to debt of 11%-12% during our two-year outlook period.

The stable outlook also reflects our view that **Enbridge Inc.** (Enbridge), the company's parent, will improve its S&P Global Ratings-adjusted credit metrics throughout the forecast period, with its debt to EBITDA decreasing to 4.7x and its FFO to debt increasing to about 16% by 2024.

Furthermore, the stable outlook reflects our expectation that both the utility's insulation features and Enbridge's strategy to preserve its credit strength will not change.

Downside scenario

We could lower our ratings on EGI if its financial measures deteriorate, including FFO to debt approaching 10% with no prospects for improvement.

Alternatively, we could lower our ratings on EGI if we lower our ratings on Enbridge. This could occur if Enbridge's consolidated S&P Global Ratings-adjusted FFO to debt falls below 13% or it sustains debt to EBITDA of more than 5x.

Upside scenario

Although unlikely, we could upgrade the company over the next 18-24 months if we also upgrade Enbridge and raise our stand-alone credit profile (SACP) on EGI.

We believe the company could warrant a higher SACP if it improves its financial measures, including FFO to debt of consistently above 13%. An upgrade at the parent level would require Enbridge to maintain FFO to debt of more than 17% and S&P Global Ratings-adjusted debt to EBITDA of about 4x while sustaining its asset mix and cash flow stability.

Our Base-Case Scenario

Assumptions

- Stable and predictable cash flows from its regulated gas distribution operations, as well as modest new customer growth;
- A stable regulatory regime in Ontario with no material adverse regulatory decisions;
- EGI will primarily operate under inflation-indexed rates throughout 2022 and 2023 before starting a new rate application cycle in 2024;

- Annual revenue increases through 2023 will be subject to a productivity stretch factor constraint of 0.3%, which reduces the annual revenue rise by the equivalent amount;
- All earnings exceeding 150 basis points over the OEB's approved return on equity will be shared equally between EGI and its ratepayers;
- EGI will earn close to its authorized return on equity;
- EGI will operate at or close to its authorized capital structure of 64%/36% debt to equity for the duration of the outlook period;
- The company continues to pass through its natural gas costs and the federal carbon levy to its ratepayers;
- Annual capital expenditure of about C$1.4 billion-C$1.6 billion between 2022 and 2024; and
- Annual dividends of about C$200 million in 2022, 2023, and 2024.

Key metrics

Enbridge Gas Inc. --Key Metrics*

	2021a	2022e	2023f
FFO to debt (%)	12.4	11-12	11-12
FFO cash interest coverage (x)	4.3	4.0-4.5	4.0-4.5
Debt to EBITDA (x)	6.2	6.0-6.5	6.0-6.5

*All figures adjusted by S&P Global Ratings. a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

EGI operates as a rate-regulated natural gas distribution utility company in Ontario, Canada. The company was formed through the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Ltd. in 2019. The company also owns and operates regulated and nonregulated natural gas storage facilities in Ontario. EGI's distribution rates are set under a five-year incentive regulation framework using a price cap mechanism and it serves about 3.8 million customers.

Peer Comparison

Enbridge Gas Inc.--Peer Comparisons

	Enbridge Gas Inc.	CU Inc.	Energir Inc.	Washington Gas Light Co.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Stable/--	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Stable/--	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual
Period ending	2021-12-31	2021-12-31	2021-09-30	2021-12-31
Mil.	C$	C$	C$	C$

Enbridge Gas Inc.--Peer Comparisons

Revenue	4,893	2,823	2,434	1,834
EBITDA	1,650	1,428	797	496
Funds from operations (FFO)	1,272	1,045	578	396
Interest	385	382	146	97
Cash interest paid	383	369	144	86
Operating cash flow (OCF)	739	1,011	439	402
Capital expenditure	1,373	994	581	599
Free operating cash flow (FOCF)	(634)	17	(143)	(197)
Discretionary cash flow (DCF)	(1,884)	(438)	(668)	(324)
Cash and short-term investments	9	121	47	0
Gross available cash	9	121	47	0
Debt	10,245	8,771	4,179	2,504
Equity	10,348	4,801	2,152	2,559
EBITDA margin (%)	33.7	50.6	32.7	27.0
Return on capital (%)	4.7	6.6	6.1	5.9
EBITDA interest coverage (x)	4.3	3.7	5.5	5.1
FFO cash interest coverage (x)	4.3	3.8	5.0	5.6
Debt/EBITDA (x)	6.2	6.1	5.2	5.1
FFO/debt (%)	12.4	11.9	13.8	15.8
OCF/debt (%)	7.2	11.5	10.5	16.1
FOCF/debt (%)	(6.2)	0.2	(3.4)	(7.9)
DCF/debt (%)	(18.4)	(5.0)	(16.0)	(12.9)

Business Risk

Our assessment of EGI's business risk reflects our view of the OEB's regulatory framework, which underpins the utility's predictable and steady cash flow. In our view, the OEB's regulatory process is transparent, consistent, and predictable. These factors collectively support the utility's timely recovery of prudently spent capital and operating expenses. In addition, the federal carbon levy flows through to EGI's customers and it recovers its gas commodity costs through a quarterly adjustment mechanism, which limits its exposure to commodity risk.

Further supporting our view is EGI's large customer base. The company serves almost all of Ontario's gas distribution network with about 3.8 million customers, most of which are residential and small business customers. As such, we expect EGI's cash flows to remain stable. However, the demand for natural gas in the residential customer class can vary due to weather-driven fluctuations, which can lead to some cash flow volatility. Our favorable view of the company's business risk is slightly offset by its limited geographic footprint and exposure to a single regulatory regime.

Financial Risk

We assess EGI's financial measures using our low volatility financial benchmark table rather than the benchmark we use for typical industrial issuers. This reflects the company's lower-risk regulated gas distribution operations and effective management of regulatory risk. EGI has a large capital program--about 2x its depreciation expense--that will cause it to generate negative discretionary cash flow and require it to rely on external financing to fund its capital programs.

Under our base-case scenario, which includes a stable regulatory environment with no material adverse regulatory decisions, we expect annual capital spending of about C$1.4 billion-C$1.6 billion, net dividend payments of about C$200 million annually, and FFO to debt of about 11%-12% between 2022 and 2024.

Debt maturities

- 2022: C$125 million;
- 2023: C$350 million;
- 2024: C$300 million;
- 2025: C$745 million; and
- 2026: C$650 million.

Financial Summary

Period ending	Dec-31-2019	Dec-31-2020	Dec-31-2021
Reporting period	2019a	2020a	2021a
Display currency (mil.)	CAD	CAD	CAD
Revenues	5,075	4,515	4,893
EBITDA	1,639	1,575	1,650
Funds from operations (FFO)	1,239	1,117	1,272
Interest expense	395	405	385
Cash interest paid	388	392	383
Operating cash flow (OCF)	1,277	1,204	739
Capital expenditures	1,104	1,180	1,373
Free operating cash flow (FOCF)	173	24	(634)
Discretionary cash flow (DCF)	(1,077)	(1,226)	(1,884)
Cash and short-term investments	77	9	9
Gross available cash	77	9	9
Debt	9,435	9,912	10,245
Common equity	10,004	10,017	10,348
Adjusted ratios			
EBITDA margin (%)	32.3	34.9	33.7
Return on capital (%)	5.3	4.7	4.7
EBITDA interest coverage (x)	4.2	3.9	4.3
FFO cash interest coverage (x)	4.2	3.9	4.3
Debt/EBITDA (x)	5.8	6.3	6.2
FFO/debt (%)	13.1	11.3	12.4
OCF/debt (%)	13.5	12.2	7.2
FOCF/debt (%)	1.8	0.2	(6.2)
DCF/debt (%)	(11.4)	(12.4)	(18.4)

Reconciliation Of Enbridge Gas Inc. Reported Amounts With S&P Global Adjusted Amounts (Mil. C$)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2021									
Company reported amounts	10,993	10,348	4,893	1,642	965	376	1,650	740	200	1,380
Cash taxes paid	-	-	-	-	-	-	5	-	-	-
Cash interest paid	-	-	-	-	-	-	(374)	-	-	-
Lease liabilities	49	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	8	2	2	(2)	6	-	-
Postretirement benefit obligations/ deferred compensation	109	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments	(9)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	7	(7)	(7)	-	(7)
Nonoperating income (expense)	-	-	-	-	(5)	-	-	-	-	-
Debt: other	(897)	-	-	-	-	-	-	-	-	-
Total adjustments	(748)	-	-	8	(3)	9	(378)	(1)	-	(7)
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	10,245	10,348	4,893	1,650	962	385	1,272	739	200	1,373

Liquidity

We assess EGI's liquidity as adequate. We expect the company's liquidity sources will be more than 1.1x its uses over the next 12 months. We also expect that its net sources would remain positive even if its EBITDA declines by 10%. In our opinion, EGI has strong relationships with its banks and generally prudent financial risk management. In the event of unexpected financial stress, we believe the utility would scale back on its capital expenditure and suspend its dividend payments to preserve liquidity.

Principal liquidity sources

- Cash of about C$8 million as of March 31, 2022;
- Committed credit facility availability of about C$2 billion;
- Cash FFO of about C$1.2 billion; and
- Working capital inflows of about C$61 million.

Principal liquidity uses

- Debt maturities of about C$1.72 billion as of March 31, 2022;
- Assumed maintenance capital spending of about C$1.1 billion over the next 12 months; and
- Net dividends of about C$200 million.

Environmental, Social, And Governance

ESG Credit Indicators

E-1	**E-2**	E-3	E-4	E-5	S-1	**S-2**	S-3	S-4	S-5	G-1	**G-2**	G-3	G-4	G-5

ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1 -5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary “ESG Credit Indicator Definitions And Applications, ” published Oct. 13, 2021.

ESG factors have no material influence on our credit rating analysis of EGI.

Group Influence

We view EGI as an insulated subsidiary in the Enbridge group. This is because EGI is incorporated as separate legal entity with a financial performance and funding that are highly independent from those of the group, including issuing long- and short-term debt, maintaining its own separate credit facilities, and not commingling its funds, assets, or cash flows with the rest of the group. In addition, there is a strong economic basis for Enbridge to preserve EGI's credit strength and we do not expect that a default at the other Enbridge group entities would directly lead to a default at EGI.

Issue Ratings--Subordination Risk Analysis

Capital structure

- As of March 31, 2022, EGI's capital structure comprised about C$1.60 billion of outstanding commercial paper and about C$9.4 billion of senior unsecured long-term debt.

Analytical conclusions

- We rate EGI's senior unsecured debt 'A-', the same level as our issuer credit rating (ICR) on EGI, because the debt is issued by a qualifying investment-grade regulated utility. Our 'A-2' rating on the commercial paper program reflects our 'A-' ICR on EGI.

Rating Component Scores

Foreign currency issuer credit rating	**A-/Stable/A-2**
Local currency issuer credit rating	**A-/Stable/A-2**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Excellent
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**a-**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Satisfactory (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a-**

Related Criteria

- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- ARCHIVE | General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- ARCHIVE | Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- ARCHIVE | General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Ratings Detail (as of July 21, 2022)*

Enbridge Gas Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Canada National Scale Commercial Paper	A-1(LOW)

Ratings Detail (as of July 21, 2022)*

Senior Unsecured	A-
Issuer Credit Ratings History	
02-Jan-2019	A-/Stable/A-2
Related Entities	
Enbridge Energy L.P.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Enbridge Energy Partners L.P.	
Issuer Credit Rating	BBB+/Stable/NR
Senior Unsecured	BBB+
Enbridge Inc.	
Issuer Credit Rating	
Foreign Currency	BBB+/Stable/A-2
Local Currency	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Preferred Stock	
Canada National Scale Preferred Share	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+
Subordinated	BBB-
Enbridge Pipelines Inc.	
Issuer Credit Rating	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	BBB+
Spectra Energy Capital LLC	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Spectra Energy Corp.	
Issuer Credit Rating	BBB+/Stable/--
Spectra Energy Partners L.P.	
Issuer Credit Rating	BBB+/Stable/NR
Senior Unsecured	BBB+
Texas Eastern Transmission L.P.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Westcoast Energy Inc.	
Issuer Credit Rating	BBB+/Stable/--

Ratings Detail (as of July 21, 2022)*

Preferred Stock	
Canada National Scale Preferred Share	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

ENBRIDGE GAS DISTRIBUTION INC.

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2012

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Gas Distribution Inc.

Financial Reporting
Management of Enbridge Gas Distribution Inc. (the Company) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and necessarily include amounts that reflect management's judgment and best estimates

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, which includes directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

(Signed)

D. Guy Jarvis
President

(Signed)

Narinder K. Kishinchandani
Vice President, Finance

February 14, 2013

February 14, 2013

Independent Auditor's Report

To the Shareholders of Enbridge Gas Distribution Inc.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2012 and December 31, 2011 and the consolidated statements of earnings, comprehensive income, changes in shareholders' equity and cash flows for each of the three years in the period ended December 31, 2012, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215, www.pwc.com/ca

pwc

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and its subsidiaries as at December 31, 2012 and December 31, 2011 and its results of operations and its cash flows for each of the three years in the period ended December 31, 2012 in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Accountants, Licensed Public Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Gas commodity and distribution revenue *(Note 20)*	**1,869**	1,880	1,781
Transportation of gas for customers	**345**	421	458
	2,214	2,301	2,239
Gas commodity and distribution costs, excluding depreciation *(Note 20)*	**(1,199)**	(1,268)	(1,236)
Gas distribution margin	**1,015**	1,033	1,003
Other revenue *(Note 4)*	**202**	103	110
	1,217	1,136	1,113
Expenses			
Operating and administrative *(Note 20)*	**449**	437	406
Depreciation and amortization	**320**	302	292
Municipal and other taxes	**40**	41	44
Earnings sharing *(Note 4)*	**10**	13	19
	819	793	761
	398	343	352
Affiliate financing income *(Note 20)*	**63**	63	63
Interest expense *(Notes 11 and 20)*	**(170)**	(172)	(186)
	291	234	229
Income taxes *(Note 17)*			
Current	**(41)**	(52)	(59)
Deferred	**(20)**	9	6
	(61)	(43)	(53)
Earnings from continuing operations	**230**	191	176
Discontinued operations *(Note 5)*			
Earnings from discontinued operations before income taxes	**6**	2	-
Income taxes from discontinued operations	**(2)**	-	-
Earnings from discontinued operations	**4**	2	-
Earnings	**234**	193	176
Preference share dividends	**(2)**	(2)	(2)
Earnings attributable to the common shareholder	**232**	191	174

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Earnings	**234**	193	176
Other comprehensive (loss)/income, net of tax *(Note 15)*			
Change in unrealized loss on cash flow hedges	**(1)**	(1)	(17)
Actuarial loss on other postretirement benefits	**(3)**	(10)	(3)
Reclassification to earnings of realized loss on cash flow hedges	**2**	2	2
Change in foreign currency translation adjustment	**-**	-	(1)
Other comprehensive loss	**(2)**	(9)	(19)
Comprehensive income	**232**	184	157
Preference share dividends	**(2)**	(2)	(2)
Comprehensive income attributable to the common shareholder	**230**	182	155

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Preference shares *(Note 13)*	**100**	100	100
Common shares *(Note 13)*			
Balance at beginning of year	**1,137**	1,071	1,071
Common shares issued	**-**	66	-
Balance at end of year	**1,137**	1,137	1,071
Additional paid-in capital			
Balance at beginning of year	**1,131**	1,131	1,131
Disposition *(Note 5)*	**17**	-	-
Balance at end of year	**1,148**	1,131	1,131
Retained earnings			
Balance at beginning of year	**32**	61	102
Earnings attributable to the common shareholder	**232**	191	174
Common share dividends declared	**(201)**	(220)	(215)
Balance at end of year	**63**	32	61
Accumulated other comprehensive loss *(Note 15)*			
Balance at beginning of year	**(24)**	(15)	4
Other comprehensive loss	**(2)**	(9)	(19)
Balance at end of year	**(26)**	(24)	(15)
Total shareholders' equity	**2,422**	2,376	2,348

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Operating activities			
Earnings	**234**	193	176
Earnings from discontinued operations	**(4)**	(2)	-
Depreciation and amortization	**320**	302	292
Deferred income taxes	**20**	(9)	(6)
Recognition of regulatory asset	**(89)**	-	-
Other	**8**	7	5
Changes in operating assets and liabilities *(Note 19)*	**77**	15	45
Cash provided by continuing operations	**566**	506	512
Cash provided by discontinued operations	**12**	3	-
	578	509	512
Investing activities			
Proceeds from sale of assets *(Note 5)*	**72**	-	-
Additions to property, plant and equipment	**(441)**	(441)	(345)
Additions to intangible assets	**(38)**	(34)	(20)
Change in construction payable	**(11)**	5	-
Other	**4**	9	-
Cash used in continuing operations	**(414)**	(461)	(365)
Financing activities			
Net change in bank overdraft	**(2)**	(10)	(11)
Net change in short-term borrowings	**35**	222	(182)
Net change in short-term note payable to affiliate company *(Note 20)*	**5**	2	(1)
Debenture and term note issues	**-**	100	402
Debenture and term note repayments	**-**	(150)	(150)
Preference share dividends	**(2)**	(2)	(2)
Common share dividends	**(206)**	(218)	(208)
Other	**-**	4	(2)
Cash used in continuing operations	**(170)**	(52)	(154)
Decrease in cash and cash equivalents	**(6)**	(4)	(7)
Cash and cash equivalents at beginning of year	**9**	13	20
Cash and cash equivalents at end of year	**3**	9	13
Cash and cash equivalents – discontinued operations	**-**	(3)	-
Cash and cash equivalents – continuing operations	**3**	6	13
Supplementary cash flow information			
Income taxes paid	**31**	62	59
Interest paid *(Note 11)*	**176**	169	185

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2012**	2011
(millions of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	**3**	6
Accounts receivable and other *(Notes 6, 17 and 20)*	**594**	659
Gas inventories	**326**	380
Assets associated with discontinued operations *(Note 5)*	**-**	7
	923	1,052
Property, plant and equipment, net *(Note 7)*	**5,532**	5,336
Investment in affiliate company *(Note 20)*	**825**	825
Deferred amounts and other assets *(Note 8)*	**432**	298
Intangible assets, net *(Note 9)*	**177**	170
Assets associated with discontinued operations *(Note 5)*	**-**	67
	7,889	7,748
Liabilities and shareholders' equity		
Current liabilities		
Bank overdraft	**5**	7
Short-term borrowings *(Note 11)*	**596**	556
Accounts payable and other *(Notes 10, 17 and 20)*	**648**	718
	1,249	1,281
Long-term debt *(Note 11)*	**2,387**	2,387
Other long-term liabilities *(Note 12)*	**1,094**	1,019
Deferred income taxes *(Note 17)*	**362**	304
Loans from affiliate company *(Notes 11 and 20)*	**375**	375
Liabilities associated with discontinued operations *(Notes 5 and 17)*	**-**	6
	5,467	5,372
Commitments and contingencies *(Notes 20 and 21)*		
Shareholders' equity		
Share capital *(Note 13)*		
Preference shares *(convertible; 4 outstanding at December 31, 2012 and 2011)*	**100**	100
Common shares *(142 outstanding at December 31, 2012 and 2011)*	**1,137**	1,137
Additional paid-in capital	**1,148**	1,131
Retained earnings	**63**	32
Accumulated other comprehensive loss *(Note 15)*	**(26)**	(24)
	2,422	2,376
	7,889	7,748

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

(Signed)

D. Guy Jarvis
President

(Signed)

David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

The Company also owns and operates unregulated natural gas storage facilities in Ontario. Between August 2011 and December 2012, the Company owned and operated two unregulated solar projects located in Amherstburg, Ontario, through a 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements of the Company are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative years. The Company is permitted to prepare its consolidated financial statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under a three-year exemption granted by securities regulators in Canada.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements.

Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 4)*; unbilled revenues *(Note 6)*; allowance for doubtful accounts *(Note 6)*; depreciation rates and carrying value of property, plant and equipment *(Note 7)*; amortization rates and carrying value of intangible assets *(Note 9)*; valuation of stock- based compensation *(Note 14)*; fair value of financial instruments *(Note 16)*; provisions for income taxes *(Note 17)*; assumptions used to measure retirement and postretirement benefit obligations *(Note 18),* commitments and contingencies *(Note 21)*; and fair value of asset retirement obligations. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its subsidiaries. All significant intercompany accounts and transactions are eliminated upon consolidation.

REGULATION

The utility operations of the Company, excluding St. Lawrence, are regulated by the Ontario Energy Board (OEB) and the utility operations of St. Lawrence are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and rate-making and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities *(Note 4)*.

REVENUE RECOGNITION

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise area.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

PUSH-DOWN ACCOUNTING

The Company has elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by the Company. Upon adopting push-down accounting, the historical cost of the Company's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage changes interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges at December 31, 2012 or 2011.

Cash Flow Hedges

The Company uses cash flow hedges to manage changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

The Company recognizes the fair value of derivative instruments on the Consolidated Statements of Financial Position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments are offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

TRANSACTION COSTS

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with Deferred amounts and other assets. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

INCOME TAXES

The liability method of accounting for income taxes is followed. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as approved by the Regulators for rate-making purposes. As a result, rates do not include the recovery of deferred income taxes related to temporary differences. A corresponding deferred income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Consolidated Statement of Financial Position. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. The effects of translating the financial statements of St. Lawrence to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/(loss) (AOCI). Asset and liability accounts are translated at the exchange rates on the date of the Consolidated Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

The Company extinguishes liabilities when a creditor has relieved the Company of its obligation, which occurs when the Company's financial institution honours a cheque that the creditor has presented for payment. Accordingly, obligations for which the Company has issued cheque payments that have not been presented to the financial institution are included in Accounts payable and other on the Consolidated Statements of Financial Position.

GAS INVENTORIES

Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators.

Included in, or deducted from, physical gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2012, $65 million (2011 - $100 million) of natural gas was held on behalf of transportation service customers. These transactions have no impact on the Company's consolidated earnings or financial position.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates authorized by the Regulators. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit.

The Regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily include: costs the Regulators have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; derivative financial instruments; and deferred financing costs. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges. Deferred financing costs are amortized using the effective interest method over the term of the related debt.

INTANGIBLE ASSETS

Intangible assets consist primarily of the Company's Customer Information System (CIS) and software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (AROs) associated with the retirement of long-lived assets would be measured at fair value and recognized as other long-term liabilities in the period in which they could be reasonably determined. The fair value would approximate the cost a third party would charge to perform the tasks necessary to retire such assets and would be recognized at the present value of expected future cash flows. AROs would be added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability would be accreted over time through charges to earnings and would be reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

It is not possible to make a reasonable estimate of AROs for the Company due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS

The Company maintains non-contributory pension plans which provide defined benefit and defined contribution pension benefits to the majority of its employees.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. During the year ended December 31, 2012, the Company refined the methodology by which it determines discount rates; in particular, refining the method by which it estimates spreads for bonds with longer term maturities. Pension cost includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension plan assets; and

- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on pension plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contributions occur.

The Company also provides other postretirement benefits (OPEB) other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans are recognized on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation.

The regulated utility operations of the Company recovered pension and OPEB expense based on amounts paid, in accordance with the methodology accepted by the Regulators for rate-making purposes. As a result, rates typically only included the recovery of required contributions. Pursuant to an OEB decision in May 2012, the Company's 2012 pension contributions were not separately recovered in rates. A November 2012 rate order from the OEB provided for future pension and OPEB costs, determined on an accrual basis, to be recovered in rates.

The Company recorded pension expenditures on a cash basis. A corresponding pension regulatory asset/liability was recorded, reflecting the Company's ability to incorporate this amount in future rates. In the absence of rate regulation, this balance would not have been recorded and pension expenditures would have been charged to earnings and OCI on the accrual basis of accounting. Pension expenditures will be recorded on the accrual basis of accounting starting in 2013.

The Company has previously recorded and will continue to record OPEB expenditures on the accrual basis of accounting. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period related to OPEB are recognized as a component of OCI, net of income taxes.

STOCK-BASED COMPENSATION

Enbridge grants stock-based compensation to certain employees and senior officers of the Company through four long-term incentive compensation plans. Compensation expense associated with each of the plans, as determined under the methods outlined below is recognized in Operating and administrative expense. Amounts owing to Enbridge in respect of stock-based compensation are payable on a quarterly basis.

Incentive Stock Options (ISOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISOs granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility.

Performance based stock options (PBSOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the PBSOs granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period. The options become exercisable when both performance targets and time vesting requirements have been met.

Performance Stock Units (PSUs) and Restricted Stock Units (RSUs) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, an expense is recorded based on the number of units outstanding and the current market price of the Company's shares. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

COMMITMENTS AND CONTINGENCIES
Liabilities for other commitments and contingencies are recognized when, after fully analyzing the available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

COMPARATIVE AMOUNTS
Certain comparative amounts have been reclassified to conform with the current year's consolidated financial statement presentation.

3. CHANGES IN ACCOUNTING POLICIES

FAIR VALUE MEASUREMENT
Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) 2011-04, which revised the existing guidance on the disclosure of fair value measurements under U.S. GAAP as part of the Financial Accounting Standard Board's joint project with the International Accounting Standards Board. Under the revised standard, the Company is required to provide additional disclosures about fair value measurements, including a description of the valuation methodologies used and information about the unobservable inputs and assumptions used in the Level 3 fair value measurements, as well as the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. As the Company does not hold any Level 3 instruments, the adoption of this update did not have an impact on the Company's consolidated financial statements.

STATEMENT OF COMPREHENSIVE INCOME
Effective January 1, 2012, the Company adopted ASU 2011-05, which updates the existing guidance on comprehensive income, requiring presentation of earnings and OCI either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of earnings and OCI. The adoption of this pronouncement did not affect the Company's presentation of comprehensive income and did not impact the Company's consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Balance Sheet Offsetting
In December 2011, the FASB issued ASU 2011-11, which provides enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. The adoption of the pronouncement affects financial statement disclosures only and is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning on or after January 1, 2013.

4. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

For the purposes of this note, "Enbridge Gas Distribution" refers specifically to Enbridge Gas Distribution Inc. excluding St. Lawrence, whereas "St. Lawrence" refers specifically to St. Lawrence Gas Company, Inc.

RATE APPROVAL
Enbridge Gas Distribution's annual rates were set using a revenue per customer cap Incentive Regulation (IR) methodology for the 2008 to 2012 period. The IR methodology adjusted revenues, and consequently rates, annually and relied on an annual process to forecast volume and customer additions.

Enbridge Gas Distribution's 2013 rates, and St. Lawrence's rates for each year, are set using a cost of service (COS) methodology that allows revenues to be set to recover costs and to earn a rate of return on common equity. Costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, municipal and other taxes, interest and income taxes. The rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under COS, it is the responsibility of Enbridge Gas Distribution and St. Lawrence to demonstrate to the Regulators the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken.

The cost of natural gas is passed on to customers as a flow-through.

APPROVED RATES

Enbridge Gas Distribution
Enbridge Gas Distribution's after-tax rate of return on common equity embedded in rates was 8.39% for the year ended December 31, 2012 (2011 – 8.39%) based on a 36% (2011 – 36%) deemed common equity component of capital for regulatory purposes.

To align the interests of customers with the Company's common shareholder, an earnings sharing mechanism formed part of the Settlement Agreement (the Settlement) with customer representatives approved by the OEB in February 2008. The Settlement encompassed all major financial aspects of the IR methodology that operated for 2008 to 2012 (inclusive). To the extent the actual utility return on the approved equity level represented by normalized earnings based on Part V – Pre-changeover accounting standards of the Canadian Institute of Chartered Accountants Handbook (Canadian GAAP) (i.e., excluding the effects of weather) (ROE) exceeded the notional allowed utility return on equity (NROE) by certain prescribed thresholds, earnings were shared with customers. The common shareholder retained the first 100 basis points of ROE above the NROE, while earnings represented by the ROE in excess of 100 basis points above the NROE were shared equally with customers.

Enbridge Gas Distribution's rates for 2013, under a COS methodology, will include an after-tax rate of return on common equity of 8.93% based on a 36% deemed common equity component of capital for regulatory purposes.

St. Lawrence
St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 10.5% for the year ended December 31, 2012 (2011 - 10.5%) based on a 50% (2011 - 50%) deemed common equity component of capital for regulatory purposes. Any earnings above a return on equity of 11% (2011 - 11%) were shared equally with customers. The calculation of such earnings was cumulative over the three-year period commencing January 1, 2010 and ending December 31, 2012, and resulted in no sharing impact as at December 31, 2012 (2011 - nil). St. Lawrence will continue operating under the existing COS agreement in 2013.

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities
As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other; long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement
The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. The Regulators' future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or refund of amounts recorded on the Consolidated Statement of Financial Position, or that would have been recorded on the Consolidated Statement of Financial Position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

FINANCIAL STATEMENT EFFECTS

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	**2012**	2011	Consolidated Statement of Financial Position Location**	Estimated Recovery/ Settlement Period *(years)*
(millions of Canadian dollars)				
Regulatory assets/(liabilities)				
Enbridge Gas Distribution				
Deferred income taxes [1]	**198**	164	DA	*
Pension plans, net [2]	**115**	103	DA/OLTL	*
OPEB [3]	**89**	-	AR/DA	20
Purchased gas variance [4]	**11**	-	AR	1
Deferred rate hearing costs [5]	**5**	3	AP/DA	2
Average use true-up variance [6]	**4**	(3)	AR	*
Unaccounted for gas variance [7]	**2**	9	AR	1
Settlement recoverable [8]	**-**	5	AR	*
Future removal and site restoration reserves [9]	**(859)**	(815)	OLTL	*
Transactional services deferral [10]	**(26)**	(7)	AP	1
Earnings sharing deferral [11]	**(10)**	(14)	AP	1
Other regulatory assets and liabilities	**3**	2	***	***
	(468)	(553)		
St. Lawrence				
Other regulatory assets and liabilities	**8**	6	***	***
	8	6		
	(460)	(547)		

* Refer to the footnote for details

** AR – Accounts receivable and other
AP – Accounts payable and other
DA – Deferred amounts and other assets
OLTL – Other long-term liabilities

*** Dependent on the nature of the item

1 *The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

2 *The pension plan balance represents the regulatory offset to the pension liability/asset to the extent the amounts are to be collected/refunded in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

3 *The OPEB balance represents the Company's right to recover OPEB costs pursuant to an OEB rate order received in November 2012. The amount will be collected in rates on a straight-line basis over a 20-year period commencing in 2013. In the absence of rate regulation, this regulatory balance and related earnings impact would not be recorded.*

4 *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In the absence of rate regulation, the actual cost of natural gas would be included in gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established.*

5 *Deferred rate hearing costs are incurred by Enbridge Gas Distribution for the regulatory process. Enbridge Gas Distribution has historically been granted OEB approval for recovery of such hearing costs, generally within two years. In the absence of rate regulation, these costs would be expensed as incurred.*

6 *Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual normalized average use for general service customers. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

7 *Unaccounted for gas variance represents the difference between the total natural gas distributed by Enbridge Gas Distribution and the amount of natural gas billed or billable to customers for their recorded consumption, to the extent it is different from the approved amount built into rates. Enbridge Gas Distribution has deferred unaccounted for gas variance and has historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation, this variance would be included in earnings in the year incurred.*

8 *Settlement recoverable deferral represents amounts paid toward the settlement of a class action lawsuit related to late payment penalties. Pursuant to an OEB decision in February 2008, these amounts were recovered from customers over a five-year period, which commenced in 2008. In the absence of rate regulation, these costs would have been expensed as incurred.*

9 *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

10 *Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.*

11 *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the IR Settlement. The earnings sharing is payable to customers and represents 50% of normalized Canadian GAAP earnings represented by the ROE in excess of 100 basis points above the NROE. The December 31, 2012 balance relates to the year ended December 31, 2012. The December 31, 2011 balance relates to the years ended December 31, 2011 and 2010. There would be no change in the treatment of this item in the absence of rate regulation.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Revenue

To recognize the actions or expected actions of the Regulators, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

In November 2012, the Company received a rate order from the OEB permitting recovery of OPEB costs in the amount of $89 million. The amount will be collected in rates on a straight-line basis over a 20-year period commencing in 2013, and is presented within Other revenue in the Consolidated Statements of Earnings. In the absence of rate regulation, this earnings impact would not have been recorded.

Operating Cost Capitalization

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs may be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2012, costs relating to this services contract of $144 million (2011 - $133 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment

In the absence of rate regulation, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred. Further, on the retirement of utility assets, the excess of the book value net of proceeds would be recorded as a loss on the sale of assets in earnings in the period of retirement. Any removal costs incurred would be booked against the future removal and site restoration balance (described above).

Intangible Assets

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2012, the net book value of these costs was $86 million (2011 - $99 million). In the absence of rate regulation, a portion of the original cost of these assets would have been expensed in the period incurred.

Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. Included in gas inventories at December 31, 2012 is $39 million (2011 - $42 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation, these costs would be expensed as incurred and inventory would be recorded at the lower of cost or market value.

Depreciation

In the absence of rate regulation, depreciation rates would not have included a charge for future removal and site restoration costs.

5. DISPOSITION AND ACQUISITION

In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to Enbridge Income Fund (the Fund), an affiliated entity under common control, for proceeds of $72 million. Project Amherstburg consisted primarily of property, plant and equipment and intangible assets. The excess of the sale price over the net book value at the time of disposition of $17 million inclusive of deferred income tax recoveries of $10 million were recognized as Additional paid-in capital. No gain or loss was recognized in earnings on the disposition; however $5 million of cash income taxes incurred on the related capital gain remains as a charge to consolidated earnings for the year ended December 31, 2012.

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company. The total consideration transferred for Project Amherstburg was approximately $66 million, which was primarily funded by the issuance of common shares (1,612,367 shares).

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2012**	2011
(millions of Canadian dollars)		
Trade receivables	**321**	377
Unbilled revenues	**170**	176
Agent billing and collection receivable	**44**	69
Regulatory assets *(Note 4)*	**32**	24
Taxes receivable	**18**	19
Due from affiliates *(Note 20)*	**12**	12
Current deferred income taxes *(Note 17)*	**5**	-
Prepaid expenses	**4**	3
Other	**29**	24
Allowance for doubtful accounts	**(41)**	(45)
	594	659

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	2012	2011
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	4.2%	3,132	2,985
Gas services	4.6%	2,530	2,418
Regulating and metering equipment	3.8%	757	719
Gas storage	3.0%	295	275
Land and right-of-way	2.5%	78	79
Computer technology	19.3%	42	35
Under construction	-	102	92
Construction materials inventory	-	38	39
Other	3.6%	284	259
		7,258	6,901
Accumulated depreciation		(1,806)	(1,649)
		5,452	5,252
Unregulated property, plant and equipment			
Gas storage	3.0%	86	88
Accumulated depreciation		(6)	(4)
		80	84
Property, plant and equipment, net		5,532	5,336

Depreciation expense, including amounts collected for future removal and site restoration costs, was $289 million for the year ended December 31, 2012 (2011 - $271 million, 2010 - $260 million).

8. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	2012	2011
(millions of Canadian dollars)		
Regulatory assets *(Note 4)*	414	277
Deferred financing costs	11	13
Pension asset *(Note 18)*	3	2
Other	4	6
	432	298

At December 31, 2012, deferred amounts of $29 million (2011 - $29 million) were subject to amortization and are presented net of accumulated amortization of $18 million (2011 - $16 million). Amortization expense for the year ended December 31, 2012 was $2 million (2011 - $2 million, 2010 - $2 million).

9. INTANGIBLE ASSETS

December 31, 2012	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	20.6%	128	37	91
CIS	10.0%	127	41	86
		255	78	177

December 31, 2011	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	20.0%	111	40	71
CIS	10.1%	127	28	99
		238	68	170

Intangible assets include $33 million of work-in-progress as at December 31, 2012 (2011 - $21 million). Total amortization expense for intangible assets was $31 million for the year ended December 31, 2012 (2011 - $31 million, 2010 - $32 million). The Company expects aggregate amortization expense for the years ending December 31, 2013 through 2017 of $37 million, $33 million, $28 million, $23 million and $20 million, respectively.

10. ACCOUNTS PAYABLE AND OTHER

December 31,	**2012**	2011
(millions of Canadian dollars)		
Operating accrued liabilities	**281**	246
Security deposits	**67**	79
Budget billing plan payable	**59**	136
Trade payables	**59**	78
Dividends payable	**51**	56
Regulatory liabilities *(Note 4)*	**39**	32
Taxes payable	**28**	26
Interest payable	**26**	26
Due to affiliates *(Note 20)*	**8**	10
Payroll payable	**8**	6
Current portion of OPEB liability *(Note 18)*	**5**	4
Current deferred income taxes *(Note 17)*	**-**	2
Other	**17**	17
	648	718

11. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2012**	2011
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	85
Medium term notes	5.51%	2014-2050	**2,295**	2,295
Commercial paper and credit facility draws, net			**590**	555
Other			**13**	8
Total debt			**2,983**	2,943
Short-term borrowings	1.10%		**(596)**	(556)
Long-term debt			**2,387**	2,387
Loans from affiliate company			**375**	375

For the years ending December 31, 2013 through 2017, medium-term note maturities are nil, $400 million, nil, nil, and $200 million respectively. The Company's debentures and medium term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2013 through 2017 are $135 million, $129 million, $113 million, $113 million, and $113 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Debentures and medium-term notes	**139**	140	149
Loans from affiliate company *(Note 20)*	**27**	27	27
Commercial paper and credit facility draws	**2**	3	2
Other interest and finance costs	**8**	8	11
Capitalized	**(6)**	(6)	(3)
	170	172	186

In 2012, total interest paid to third parties was $142 million (2011 - $149 million, 2010 - $158 million) and total interest paid to affiliate company was $34 million (2011 - $20 million, 2010 - $27 million).

CREDIT FACILITIES

The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option.

December 31, 2012	Maturity Dates	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc.	2014	**700**	**580**	**120**
St. Lawrence Gas Company, Inc.	2014	**12**	**10**	**2**
Total credit facilities		**712**	**590**	**122**

1 Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the credit facility.

Credit facilities carried a weighted average standby fee of 0.22% per annum from January to August 2012 and 0.20% per annum from September to December 2012 on the unused portion and draws bear interest at market rates.

The Company's borrowings, whether debentures or medium-term notes, are unsecured. When issuing any new indebtedness with a maturity over 18 months, covenants contained in the Company's trust indenture require the pro forma long-term debt interest coverage ratio be at least 2.0 times for 12 consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as U.S. GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of financing costs and intercompany interest expense less gains on asset dispositions divided by the annual interest requirement. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. As at December 31, 2012, the Company was in compliance with this covenant.

12. OTHER LONG-TERM LIABILITIES

December 31,	**2012**	2011
(millions of Canadian dollars)		
Regulatory liabilities *(Note 4)*	**867**	816
Pension and OPEB liabilities *(Note 18)*	**226**	203
Other	**1**	-
	1,094	1,019

13. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preference shares.

COMMON SHARES

	2012		2011		2010	
December 31,	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**142.3**	**1,137**	140.7	1,071	140.7	1,071
Common shares issued	**-**	**-**	1.6	66	-	-
Balance at end of year	**142.3**	**1,137**	142.3	1,137	140.7	1,071

PREFERENCE SHARES

December 31, 2012, 2011, and 2010	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preference shares in millions)			
Group 1	0.2	-	-
Group 2, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 2, Series D, Cumulative Redeemable Convertible	4	-	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	-	-
Group 5	10	-	-
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preference shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference shares on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preference shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

14. STOCK OPTION AND STOCK UNIT PLANS

Enbridge's four long-term incentive compensation plans include the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. The Company reimburses Enbridge for stock-based compensation costs associated with its employees on a quarterly basis.

STOCK SPLIT

Effective May 25, 2011, a two-for-one split of the common shares of Enbridge was completed. All references to the outstanding option information have been retroactively restated to reflect the impact of the stock split.

INCENTIVE STOCK OPTIONS

Key employees of the Company are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2012	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**2,568**	**20.84**		
Options granted	**480**	**38.34**		
Options exercised[1]	**(521)**	**17.35**		
Options outstanding at end of year	**2,527**	**24.88**	**6.3**	**37**
Options vested at end of year[2]	**1,305**	**19.38**	**4.6**	**26**

1 The total intrinsic value of ISOs exercised during the year ended December 31, 2012 was $11 million (2011 - $8 million; 2010 - $4 million) and cash received by Enbridge on exercise was $6 million (2011 - $7 million; 2010 - $6 million).

2 The total fair value of options vested under the ISO Plan during the year ended December 31, 2012 was $2 million (2011 - $1 million; 2010 - $1 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2012**	2011	2010
Fair value per option *(Canadian dollars)*[1]	**4.81**	4.19	3.44
Valuation assumptions			
Expected option term *(years)*[2]	**5**	6	6
Expected volatility[3]	**19.7%**	18.6%	19.7%
Expected dividend yield[4]	**3.0%**	3.4%	3.6%
Risk-free interest rate[5]	**1.3%**	2.9%	2.7%

1 Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $4.65 (2011 - $4.01; 2010 - $3.28) for Canadian employees and US$5.58 (2011 - US$5.11, 2010 - US$4.00) for United States employees.

2 The expected option term is based on historical exercise practice.

3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.

4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.

5 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.

Compensation expense recorded for the year ended December 31, 2012 for ISOs was $3 million (2011 - $3 million, 2010 - $2 million). At December 31, 2012, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $3 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted by Enbridge to executive officers of the Company and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on August 15, 2012 under the 2007 plan. Time vesting requirements for the 2012 grant are fulfilled evenly over a five-year term, ending August 15, 2017. The 2012 grant's performance targets are based on Enbridge's share price and must be met by February 15, 2019 or the options expire. If targets are met by February 15, 2019, the options are exercisable until August 15, 2020.

December 31, 2012	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**-**	**-**		
Options granted	**169**	**39.34**		
Options outstanding at end of year	**169**	**39.34**	**7.6**	**8**

Weighted average assumptions used to determine the fair value of the PBSOs using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	**2012**
Fair value per option *(Canadian dollars)*	**4.25**
Valuation assumptions	
Expected option term *(years)*[1]	**8**
Expected volatility[2]	**16.1%**
Expected dividend yield[3]	**2.8%**
Risk-free interest rate[4]	**1.6%**

1 *The expected option term is based on historical exercise practice.*
2 *Expected volatility is determined with reference to historic daily share price volatility.*
3 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*
4 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields.*

Compensation expense for PBSOs was nil for the years ended December 31, 2012, 2011 and 2010. At December 31, 2012, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the PBSO Plan was $1 million. The cost is expected to be fully recognized over a weighted average period of approximately five years.

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan for senior officers of the Company where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average common share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two, if Enbridge performs within the highest range of its performance targets. The 2010, 2011 and 2012 grants derive the performance multiplier through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2012 expense, multipliers of two, based upon multiplier estimates at December 31, 2012, were used for each of the 2010, 2011 and 2012 PSU grants.

December 31, 2012	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**37**		
Units granted	**16**		
Units matured[1]	**(19)**		
Dividend reinvestment	**2**		
Units outstanding at end of year	**36**	**1.5**	**3**

1 *The total amount paid by Enbridge during the year ended December 31, 2012 for PSUs was $1 million (2011 - $1 million; 2010 - nil).*

Compensation expense recorded for the year ended December 31, 2012 for PSUs was $7 million (2011 - $6 million; 2010 - $4 million). As of December 31, 2012, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $2 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a RSU Plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2012	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**254**		
Units granted	**103**		
Units cancelled	**(7)**		
Units matured[1]	**(132)**		
Dividend reinvestment	**10**		
Units outstanding at end of year	**228**	**1.4**	**10**

1 The total amount paid by Enbridge during the year ended December 31, 2012 for RSUs was $5 million (2011 - $5 million; 2010 - $3 million).

Compensation expense recorded for the year ended December 31, 2012 for RSUs was $5 million (2011 - $5 million; 2010 - $5 million). As of December 31, 2012, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $5 million and is expected to be fully recognized over a weighted average period of less than two years.

15. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

	Cash Flow Hedges	Cumulative Translation Adjustment	OPEB Actuarial Loss Adjustment	Total
(millions of Canadian dollars)				
Balance at January 1, 2010	3	(5)	6	4
Changes during the year	(14)	(1)	(4)	(19)
Tax impact	(1)	-	1	-
	(15)	(1)	(3)	(19)
Balance at December 31, 2010	(12)	(6)	3	(15)
Changes during the year	1	-	(13)	(12)
Tax impact	-	-	3	3
	1	-	(10)	(9)
Balance at December 31, 2011	(11)	(6)	(7)	(24)
Changes during the year	**1**	**-**	**(4)**	**(3)**
Tax impact	**-**	**-**	**1**	**1**
	1	**-**	**(3)**	**(2)**
Balance at December 31, 2012	**(10)**	**(6)**	**(10)**	**(26)**

16. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

MARKET PRICE RISK

The Company's earnings, cash flows and OCI are subject to movements in interest rates, foreign exchange rates and natural gas prices (collectively, market price risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses qualifying derivative instruments to manage some of the risks noted below.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Floating to fixed interest rate swaps and options are used to mitigate the volatility of short-term interest rates on interest expense on variable rate debt.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is nil (2011 - nil).

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer, therefore, the net exposure to the Company is nil (2011 - nil).

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the location on the Consolidated Statements of Financial Position and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges or net investment hedges at December 31, 2012 or 2011.

December 31,	**2012**	2011
(millions of Canadian dollars)		
Deferred amounts and other assets		
Interest rate contracts	**1**	-
Accounts payable and other		
Interest rate contracts	**(1)**	(1)
Other long-term liabilities		
Interest rate contracts	**(1)**	-
Total net derivative liability		
Interest rate contracts	**(1)**	(1)

1 As presented in the Consolidated Statements of Financial Position.

The Company's derivatives instruments mature through 2017 and have a notional principal of $673 million for interest rate contracts for short-term borrowings (2011 - $111 million), and $1,007 million for interest rate contracts on long-term debt (2011 - nil).

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Amount of unrealized loss recognized in OCI			
Cash flow hedges			
Interest rate contracts	**(1)**	(2)	(25)
	(1)	(2)	(25)
Amount of loss reclassified from accumulated other comprehensive loss to earnings *(effective portion)*			
Interest rate contracts[1]	**2**	3	3
	2	3	3

1 Loss reported within Interest expense in the Consolidated Statements of Earnings.

The Company estimates that no AOCI related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 60 months at December 31, 2012.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees *(Notes 20 and 21)* as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations and the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains a current shelf prospectus with securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. As at December 31, 2012, the Company had filed a preliminary shelf prospectus, and the final prospectus was filed in January 2013 *(Note 22)*. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 11)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2012. As a result, all credit facilities are available to the Company and the banks are obligated to fund, and have been funding, the Company under the terms of the facilities.

CREDIT RISK

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts.

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate. Under IR, these estimated costs recovered through distribution rates related to the base year of the IR plan (2007) and were escalated by the approved formula during the IR term.

Entering into derivative financial instruments may also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

The Company generally has a policy of entering into individual International Securities Dealers Association (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with those specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

At December 31, 2012, the Company had a maximum exposure to credit risk of $1 million (2011 - nil) related to its derivative counterparties.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

Fair Value of Derivatives

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company does not have any derivative instruments classified as Level 1.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps for which observable inputs can be obtained.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2012, the Company had Level 2 derivative assets with fair value of $1 million (2011 - nil), and Level 2 derivative liabilities with fair value of $2 million (2011 - $1 million).

The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at December 31, 2012 or 2011.

Fair Value of Other Financial Instruments
The Company's investment in IPL System Inc., an affiliate company, is a preference share investment carried at a cost of $825 million at December 31, 2012 (2011 - $825 million), which approximates its fair value and redemption value.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure, and is classified as a Level 2 measurement. At December 31, 2012, the Company's long-term debt had a carrying value of $2,387 million (2011 - $2,387 million) and a fair value of $2,994 million (2011 - $2,943 million).

The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity.

17. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations	**291**	234	229
Combined statutory income tax rate	**26.5%**	28.3%	31.0%
Income taxes at statutory rate	**77**	66	71
Increase/(decrease) resulting from:			
Deferred income taxes related to regulated operations	**(13)**	-	7
Non-taxable dividend income from affiliate company	**(17)**	(18)	(19)
Tax rates and legislated tax changes	**8**	-	-
Intercompany sale of investment[1]	**5**	-	-
Other	**1**	(5)	(6)
Income taxes before discontinued operations	**61**	43	53
Effective income tax rate	**20.9%**	18.3%	23.0%

1 *In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund. As the transaction occurred between entities under common control of Enbridge, the intercompany gain realized as a result of this transfer has been eliminated, although cash income taxes of $5 million remain as a charge to earnings.*

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2012**	2011
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(317)**	(290)
Investments	**-**	(6)
Reserves	**(23)**	-
Regulatory assets	**(52)**	(41)
Other	**-**	(2)
Total deferred income tax liabilities	**(392)**	(339)
Deferred income tax assets		
Financial derivatives	**4**	4
Retirement and postretirement benefits	**23**	23
Other	**8**	-
Total deferred income tax assets	**35**	27
Net deferred income tax liabilities	**(357)**	(312)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 6)*	**5**	-
Total deferred income tax assets	**5**	-
Liabilities		
Deferred income taxes	**(362)**	(304)
Accounts payable and other *(Note 10)*	**-**	(2)
Liabilities associated with discontinued operations	**-**	(6)
Total deferred income tax liabilities	**(362)**	(312)
Net deferred income tax liabilities	**(357)**	(312)

The Company has assessed all tax positions. As a result, no significant adjustments were required to be made to the income tax provisions for the year ended December 31, 2012.

The Company and its subsidiaries are subject to taxation in Canada. The Company is open to examination by certain tax authorities for the 2008 to 2012 tax years. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario).

18. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

The Company maintains a non-contributory basic pension plan that provides either defined benefit or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees.

A measurement date of December 31, 2012 was used to determine the plan assets and accrued benefit obligation for the pension plans.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective date of the most recently filed actuarial valuation was December 31, 2009. The effective date of the next required actuarial valuation is December 31, 2012.

Defined Contribution Plans
Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

OTHER POSTRETIREMENT BENEFITS
OPEB primarily includes supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS
The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension		OPEB	
December 31,	**2012**	2011	**2012**	2011
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**852**	702	**103**	87
Service cost	**21**	16	**2**	1
Interest cost	**37**	39	**4**	5
Actuarial loss	**33**	127	**5**	13
Benefits paid	**(37)**	(33)	**(3)**	(3)
Other	**(1)**	1	**1**	-
Benefit obligation at end of year	**905**	852	**112**	103
Change in plan assets				
Fair value of plan assets at beginning of year	**744**	759	**6**	4
Transfer to the defined contribution component	**-**	(1)	**-**	-
Actual return on plan assets	**59**	15	**1**	-
Employer's contributions	**17**	4	**4**	6
Benefits paid	**(37)**	(33)	**(3)**	(3)
Other	**(1)**	-	**(1)**	(1)
Fair value of plan assets at end of year	**782**	744	**7**	6
Underfunded status at end of year	**(123)**	(108)	**(105)**	(97)
Presented as follows:				
Deferred amounts and other assets *(Note 8)*	**3**	2	**-**	-
Accounts payable and other *(Note 10)*	**-**	-	**(5)**	(4)
Other long-term liabilities *(Note 12)*	**(126)**	(110)	**(100)**	(93)

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2012**	2011	2010	**2012**	2011	2010
Discount rate	**4.3%**	4.5%	5.7%	**4.3%**	4.5%	5.7%
Average rate of salary increases	**3.5%**	3.5%	3.5%	**3.5%**	5.0%	5.0%

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2012**	2011	2010	**2012**	2011	2010
(millions of Canadian dollars)						
Benefits earned during the year	**21**	16	12	**2**	1	1
Interest cost on projected benefit obligations	**37**	39	39	**4**	5	5
Actual return on plan assets	**(59)**	(15)	(78)	**(1)**	-	-
Actuarial loss	**33**	127	79	**5**	13	5
Difference between actual and expected return on plan assets						
Return on plan assets	**10**	(38)	29	**-**	-	-
Amortization of prior service costs	**1**	2	1	**-**	-	-
Amortization of actuarial loss	**(3)**	(110)	(64)	**(4)**	(13)	(5)
Net defined benefit costs on an accrual basis	**40**	21	18	**6**	6	6
Defined contribution benefit costs	**1**	1	2	**-**	-	-
Net benefit cost recognized on an accrual basis	**41**	22	20	**6**	6	6
Net amount recognized in OCI						
Net actuarial loss[1]	**-**	-	-	**4**	13	4
Total amount recognized in OCI	**-**	-	-	**4**	13	4
Total net benefit cost on an accrual basis and amount recognized in OCI	**41**	22	20	**10**	19	10

1 *Unamortized actuarial losses included in AOCI, before tax, were $14 million relating to OPEB at December 31, 2012 (2011 - $10 million loss, 2010 - $3 million gain).*

The Company estimates that approximately $29 million related to pension plans and OPEB at December 31, 2012 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Prior service costs	**1**	**-**	**1**
Actuarial Loss	**28**	**-**	**28**
	29	**-**	**29**

Regulatory adjustments were recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for rate-making purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers in future rates *(Note 4)*.

Pension costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension costs due to the regulatory mechanism in place. As a result, the net pension expense primarily consisted of contributions to the pension plan. Such costs totaled $18 million for pension benefits for the year ended December 31, 2012 (2011 – $4 million, 2010 – $4 million).

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2012**	2011	2010	**2012**	2011	2010
Discount rate	**4.5%**	5.7%	6.6%	**4.5%**	5.7%	6.6%
Average rate of return on pension plan assets	**7.0%**	7.3%	7.1%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.5%**	3.5%	3.5%	**5.0%**	5.0%	5.0%

MEDICAL COST TRENDS
The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in Which Ultimate Medical Cost Trend Rate Assumption is Achieved
Drugs	8.2%	4.5%	2029
Other medical and dental	4.5%	4.5%	-

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $13 million in the accumulated postretirement benefit obligations and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $10 million in the accumulated postretirement benefit obligations and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS
The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of the liabilities of the plans; (ii) the investment horizon of the plans; (iii) the going concern and solvency funded status and cash flow requirements of the plans; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2012**	2011	**2012**	2011
Expected rate of return	**7.0%**	7.3%	**-**	-

Target Mix for Plan Assets

Equity securities	44.5%
Fixed income securities	40.0%
Other	15.5%

Major Categories of Plan Assets
Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2012, the pension assets were invested in 60% (2011 – 55%) in equity securities, 37% (2011 – 44%) in fixed income securities and 3% (2011 – 1%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $8 million (2011 - $19 million) have been excluded from the table below.

	2012				2011			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension Benefits								
Cash and cash equivalents	**18**	**-**	**-**	**18**	4	-	-	4
Fixed income securities								
Canadian government real return bonds	**57**	**-**	**-**	**57**	82	-	-	82
Canadian corporate bond index fund	**109**	**5**	**-**	**114**	237	-	-	237
Canadian government bond index fund	**109**	**-**	**-**	**109**	-	-	-	-
United States bond index fund	**-**	**2**	**-**	**2**	-	-	-	-
Equity								
Canadian equity securities	**113**	**-**	**-**	**113**	90	-	-	90
Canadian equity funds	**4**	**59**	**-**	**63**	47	-	-	47
United States equity funds	**58**	**13**	**-**	**71**	-	-	-	-
Global equity funds	**100**	**74**	**-**	**174**	221	-	-	221
Private equity investment[4]	**-**	**-**	**38**	**38**	-	-	44	44
Real estate[5]	**-**	**-**	**15**	**15**	-	-	-	-
OPEB								
Cash and cash equivalents	**1**	**-**	**-**	**1**	-	-	-	-
Fixed income securities								
United States municipal bonds	**2**	**-**	**-**	**2**	-	-	-	-
Global bond fund	**-**	**-**	**-**	**-**	-	3	-	3
Equity								
United States equity fund	**2**	**2**	**-**	**4**	-	-	-	-
Global equity fund	**-**	**-**	**-**	**-**	-	3	-	3

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair value of the investment in Global Infrastructure Limited Partnership is established through the use of valuation models.
5 The fair value of the investment in Bentall Kennedy Prime Canadian Property Fund Ltd is established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2012**	2011
Balance at beginning of year	**44**	42
Unrealized and realized gains	**7**	6
Purchases and settlements, net	**2**	(4)
Balance at end of year	**53**	44

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension		OPEB	
Year ended December 31,	**2012**	2011	**2012**	2011
(millions of Canadian dollars)				
Total contributions	**18**	4	**4**	6
Contributions expected to be paid in 2013	**45**		**5**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2013	2014	2015	2016	2017	2018-2022
(millions of Canadian dollars)						
Expected future benefit payments	41	44	47	49	51	290

19. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	2012	2011	2010
(millions of Canadian dollars)			
Accounts receivable and other	**74**	139	8
Gas inventories	**54**	20	(4)
Accounts payable and other	**(51)**	(144)	41
	77	15	45

SIGNIFICANT NON-CASH ITEMS

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares.

20. RELATED PARTY TRANSACTIONS

All related party transactions, other than those disclosed under Other Transactions, are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Year ended December 31,	2012	2011	2010
(millions of Canadian dollars)			
IPL System Inc.			
Dividend income	**63**	63	63
Interest expense	**27**	27	27
Enbridge			
Purchase of treasury and other management services	**39**	34	32
Gazifère Inc.			
Revenue from wholesale service, including gas sales	**25**	28	30
Vector Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**24**	24	27
Vector Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**2**	2	1
Alliance Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**25**	25	25
Alliance Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**18**	18	17
Enbridge Commercial Services Inc.			
Purchase of information services	**-**	-	2

The Company had related party balances as follows:

December 31,	**2012**	2011
(millions of Canadian dollars)		
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**2**	9
Note payable to affiliate company		
Enbridge (U.S.)	**13**	8
Other accounts receivables/(payables)		
Enbridge	**(7)**	(1)
Gazifère Inc.	**4**	4
Enbridge Pipelines Inc.	**3**	1
Niagara Gas Transmission Ltd.	**-**	2

Financing Transactions

The Company has invested in Class D, non-voting, redeemable, retractable preference shares of IPL System Inc., an affiliate under common control. At December 31, 2012, the investment of $825 million (2011 - $825 million) in these shares resulted in a weighted average dividend yield of 7.60%.

At December 31, 2012, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.50%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preference shares of the Company. For the year ended December 31, 2012, interest paid amounted to $34 million (2011 - $20 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 0.55% and is payable on demand.

Treasury and Other Management Services

Enbridge provides treasury and other management services and charges the Company on a cost recovery basis.

Wholesale Service

These gas procurement and transportation services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Transportation Services

The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2013 – $69 million, 2014 to 2015 – $120 million, and nil thereafter.

Information Services

The Company purchases access to a few of its customer care information systems from Enbridge Commercial Services Inc. (ECS), an affiliate under common control. ECS charges the Company amounts under a service level agreement designed to recover the cost of providing the service.

Trade Receivables and Payables

The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is charged. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

Other Transactions
In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund, an affiliated entity under common control, for cash proceeds of $72 million *(Note 5)*.

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares *(Note 5)*.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

21. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $1,183 million which are expected to be paid within the next five years and $149 million in total for years thereafter.

Minimum future payments under operating leases are estimated at $12 million in aggregate. Estimated annual lease payments for the years ended December 31, 2013 through 2017 are $3 million, $3 million, $3 million, $3 million and nil, respectively. Total rental expense for operating leases, classified in Operating and administrative expense, were $3 million, $3 million, and $2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

CONTINGENCIES

Former Manufactured Coal Gas Plant Sites
The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2013 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

OTHER LITIGATON

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

22. SUBSEQUENT EVENT

An $800 million shelf prospectus filed in November 2010 expired during the fourth quarter of 2012. A new $800 million shelf prospectus was filed in January 2013 and will be effective for a 25 month period.

CORPORATE INFORMATION

TRUSTEE AND REGISTRARS

Debenture
9.85% debenture

CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6
and in Montreal, Calgary and Vancouver

For the above debenture, CIBC Mellon Trust Company of Canada is the Interest Dispersing Agent.

REGISTRAR AND PAYING AGENT

Medium Term Notes
Canadian Imperial Bank of Commerce
Debt Management Service
22 Front Street West, 5th Floor
Toronto, Ontario, M5J 2W5

TRUSTEE

Medium Term Notes
CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6

REGISTRAR AND TRANSFER AGENT

Group 3 Preference Shares
Computershare Investor Services Inc.
100 University Avenue, 8th Floor
Toronto, Ontario, M5J 2Y1

CORPORATE GOVERNANCE

The size of the Board of Directors of the Company is currently set at six (6) members, two (2) of whom are considered to be independent directors.

The Board has an Audit, Finance & Risk Committee comprised of the following directors:

J. L. Braithwaite
D. A. Leslie
J. R. Bird

The Audit, Finance & Risk Committee's key responsibilities include the review of the consolidated financial statements, and systems of internal financial and compliance control.

The governance of the Company is the responsibility of the Board of Directors and the Audit, Finance & Risk Committee of the Board, who are also responsible under law for the supervision of the management of the Company's businesses and affairs and have the statutory authority and obligation to act honestly and in good faith with a view to the best interests of the Company.

The Board makes independent decisions and also receives recommendations from the following committees of the Enbridge Inc. Board of Directors, who act in an advisory capacity to the Board of Directors of the Company:

- Governance Committee
- Human Resources & Compensation Committee
- Corporate Social Responsibility Committee

In addition to the committee structure and mandate of the Board of Directors outlined above, the Board of Directors has adopted and governs itself in accordance with Enbridge Inc.'s corporate governance practices as expressed in the *Corporate Governance Practices* of Enbridge annually disclosed in its *Management Information Circular* (last dated March 2, 2012), which is incorporated herein by reference.

ENBRIDGE GAS DISTRIBUTION INC.
(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2013

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Gas Distribution Inc.

Financial Reporting
Management of Enbridge Gas Distribution Inc. (the Company) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with U.S. GAAP and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

(Signed)

Glenn W. Beaumont
President

(Signed)

William M. Ramos
Vice President, Finance & Regulatory

February 13, 2014

February 13, 2014

Independent Auditor's Report

To the Shareholders of
Enbridge Gas Distribution Inc.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2013 and December 31, 2012 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2013, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215, www.pwc.com/ca

pwc

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and its subsidiaries as at December 31, 2013 and December 31, 2012 and its results of operations and its cash flows for each of the three years in the period ended December 31, 2013 in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Gas commodity and distribution revenue *(Note 21)*	**2,221**	1,869	1,880
Transportation of gas for customers	**328**	345	421
	2,549	2,214	2,301
Gas commodity and distribution costs, excluding depreciation *(Note 21)*	**(1,480)**	(1,229)	(1,296)
Gas distribution margin	**1,069**	985	1,005
Other revenue *(Note 5)*	**99**	202	103
	1,168	1,187	1,108
Expenses			
Operating and administrative *(Note 21)*	**454**	449	437
Depreciation and amortization *(Note 3)*	**304**	320	302
Municipal and other taxes	**42**	40	41
Earnings sharing *(Note 5)*	**-**	10	13
	800	819	793
	368	368	315
Affiliate financing income *(Note 21)*	**63**	63	63
Interest expense *(Notes 12 and 21)*	**(171)**	(170)	(172)
	260	261	206
Income taxes *(Note 18)*			
Current	**(52)**	(33)	(44)
Deferred	**9**	(20)	9
	(43)	(53)	(35)
Earnings from continuing operations	**217**	208	171
Discontinued operations *(Note 6)*			
Earnings from discontinued operations before income taxes	**-**	6	2
Income taxes from discontinued operations	**-**	(2)	-
Earnings from discontinued operations	**-**	4	2
Earnings	**217**	212	173
Preference share dividends *(Note 14)*	**(2)**	(2)	(2)
Earnings attributable to the common shareholder	**215**	210	171

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Earnings	**217**	212	173
Other comprehensive income/(loss), net of tax *(Note 16)*			
Change in unrealized gain/loss on cash flow hedges	**81**	(1)	(1)
Reclassification to earnings of realized loss on cash flow hedges	**1**	2	2
Reclassification to earnings of unrealized gain on cash flow hedges	**(2)**	-	-
Actuarial gain/(loss) on other postretirement benefits *(Note 19)*	**10**	(3)	(10)
Change in foreign currency translation adjustment	**1**	-	-
Other comprehensive income/(loss)	**91**	(2)	(9)
Comprehensive income	**308**	210	164
Preference share dividends	**(2)**	(2)	(2)
Comprehensive income attributable to the common shareholder	**306**	208	162

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Preference shares *(Note 14)*	**100**	100	100
Common shares *(Note 14)*			
Balance at beginning of year	**1,137**	1,137	1,071
Common shares issued	**150**	-	66
Balance at end of year	**1,287**	1,137	1,137
Additional paid-in capital			
Balance at beginning of year	**1,148**	1,131	1,131
Disposition *(Note 6)*	**-**	17	-
Balance at end of year	**1,148**	1,148	1,131
Retained earnings/(deficit)			
Balance at beginning of year	**7**	(2)	47
Earnings attributable to the common shareholder	**215**	210	171
Common share dividends declared	**(200)**	(201)	(220)
Balance at end of year	**22**	7	(2)
Accumulated other comprehensive income/(loss) *(Note 16)*			
Balance at beginning of year	**(26)**	(24)	(15)
Other comprehensive income/(loss)	**91**	(2)	(9)
Balance at end of year	**65**	(26)	(24)
Total shareholders' equity	**2,622**	2,366	2,342

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Operating activities			
Earnings	**217**	212	173
Earnings from discontinued operations	**-**	(4)	(2)
Depreciation and amortization	**304**	320	302
Deferred income taxes	**(9)**	20	(9)
Recognition of regulatory asset *(Note 5)*	**-**	(89)	-
Other	**12**	13	9
Premium on issuance of term notes	**12**	-	-
Changes in operating assets and liabilities *(Note 20)*	**(86)**	71	15
Cash provided by continuing operations	**450**	543	488
Cash provided by discontinued operations *(Note 6)*	**-**	12	3
	450	555	491
Investing activities			
Additions to property, plant and equipment	**(519)**	(414)	(414)
Additions to intangible assets	**(34)**	(38)	(34)
Change in construction payable	**6**	(11)	5
Proceeds on sale of assets *(Note 6)*	**-**	72	-
	(547)	(391)	(443)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**(210)**	33	212
Net change in short-term note payable to affiliate company *(Note 21)*	**2**	5	2
Debenture and term note issues	**400**	-	100
Debenture and term note repayments	**-**	-	(150)
Common shares issued *(Note 14)*	**150**	-	-
Preference share dividends	**(2)**	(2)	(2)
Common share dividends	**(200)**	(206)	(218)
Other	**(2)**	-	4
	138	(170)	(52)
Increase/(decrease) in cash and cash equivalents	**41**	(6)	(4)
Cash and cash equivalents at beginning of year	**3**	9	13
Cash and cash equivalents at end of year	**44**	3	9
Cash and cash equivalents – discontinued operations *(Note 6)*	**-**	-	(3)
Cash and cash equivalents – continuing operations	**44**	3	6
Supplementary cash flow information			
Income taxes paid	**42**	31	62
Interest paid *(Note 12)*	**169**	176	169

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2013**	2012
(millions of Canadian dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**44**	3
Accounts receivable and other *(Notes 7, 18 and 21)*	**706**	605
Gas inventories *(Note 2)*	**382**	341
	1,132	949
Property, plant and equipment, net *(Note 8)*	**5,869**	5,532
Investment in affiliate company *(Note 21)*	**825**	825
Deferred amounts and other assets *(Note 9)*	**379**	432
Intangible assets, net *(Note 10)*	**174**	177
	8,379	7,915
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**4**	5
Short-term borrowings *(Note 12)*	**389**	596
Accounts payable and other *(Notes 11 and 21)*	**769**	730
Current maturities of long-term debt *(Note 12)*	**400**	-
	1,562	1,331
Long-term debt *(Note 12)*	**2,399**	2,387
Other long-term liabilities *(Note 13)*	**1,026**	1,094
Deferred income taxes *(Note 18)*	**395**	362
Loans from affiliate company *(Notes 12 and 21)*	**375**	375
	5,757	5,549
Commitments and contingencies *(Notes 21 and 22)*		
Shareholders' equity		
Share capital *(Note 14)*		
Preference shares *(convertible; 4 outstanding at December 31, 2013 and 2012)*	**100**	100
Common shares *(151 and 142 outstanding at December 31, 2013 and 2012, respectively)*	**1,287**	1,137
Additional paid-in capital	**1,148**	1,148
Retained earnings	**22**	7
Accumulated other comprehensive income/(loss) *(Note 16)*	**65**	(26)
	2,622	2,366
	8,379	7,915

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

(Signed)

Glenn W. Beaumont
President

(Signed)

David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

The Company also owns and operates regulated and unregulated natural gas storage facilities in Ontario. Between August 2011 and December 2012, the Company owned and operated two unregulated solar projects located in Amherstburg, Ontario, through a 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. The Company is permitted to prepare its consolidated financial statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under an exemption granted by securities regulators in Canada.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues *(Note 7)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 8)*; amortization rates and carrying value of intangible assets *(Note 10)*; valuation of stock- based compensation *(Note 15)*; fair value of financial instruments *(Note 17)*; provisions for income taxes *(Note 18)*; assumptions used to measure retirement and other postretirement benefit obligations (OPEB) *(Note 19),* commitments and contingencies *(Note 22)*; and fair value of asset retirement obligations (ARO). Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its subsidiaries. All significant intercompany accounts and transactions are eliminated upon consolidation.

REGULATION

The utility operations of the Company, excluding St. Lawrence, are regulated by the Ontario Energy Board (OEB) and the utility operations of St. Lawrence are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities *(Note 5)*.

REVENUE RECOGNITION

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise area.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

PUSH-DOWN ACCOUNTING

The Company has elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by the Company. Upon adopting push-down accounting, the historical cost of the Company's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges at December 31, 2013 or 2012.

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/loss (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

The Company recognizes the fair value of derivative instruments on the Consolidated Statements of Financial Position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with Deferred amounts and other assets. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

INCOME TAXES

The liability method of accounting for income taxes is followed. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as approved by the Regulators for rate-making purposes. As a result, rates do not include the recovery of deferred income taxes related to temporary differences. A corresponding deferred income tax regulatory liability/asset is recorded reflecting the Company’s ability to pay/collect the amounts in the future through rates.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Consolidated Statement of Financial Position. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The functional currency of the Company’s only foreign operation, St. Lawrence, is the United States dollar. The effects of translating the financial statements of St. Lawrence to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI). Asset and liability accounts are translated at the exchange rates in effect on the date of the Consolidated Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

The Company extinguishes liabilities when a creditor has relieved the Company of its obligation, which occurs when the Company’s financial institution honours a cheque that the creditor has presented for payment. Accordingly, obligations for which the Company has issued cheque payments that have not been presented to the financial institution are included in Accounts payable and other on the Consolidated Statements of Financial Position.

GAS INVENTORIES

Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators’ approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators.

Included in, or deducted from, physical gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2013, $28 million (2012 - $51 million) of natural gas was held on behalf of transportation service customers. These transactions have no impact on the Company's consolidated earnings or financial position.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates authorized by the Regulators. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit.

The Regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily include: costs which the Regulators have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; derivative financial instruments; and deferred financing costs. Deferred financing costs are amortized using the effective interest method over the term of the related debt.

INTANGIBLE ASSETS

Intangible assets consist primarily of the Company's Customer Information System (CIS) and software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS

ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. In 2013, new mortality assumptions were adopted by the Company for the measurement of the December 31, 2013 benefit obligations, moving from the tables previously issued by the Canadian Institute of Actuaries (CIA) to the proposed revised tables. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. During the year ended December 31, 2012, the Company refined the methodology by which it determines discount rates, in particular, refining the method by which it estimates spreads for bonds with longer term maturities. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contributions occur.

The Company also provides OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities, respectively, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

The Company expects to recover pension expense in future rates and therefore records a corresponding regulatory asset to the extent such recovery is deemed to be probable. For years prior to 2012, a regulatory asset related to OPEB obligation was not recorded as a rate order allowing for the recovery of these costs in rates had not yet been obtained. Commencing in 2012, pursuant to a specific rate order allowing for recovery in rates of OPEB costs determined on an accrual basis in rates, a corresponding regulatory asset was recognized. In the absence of rate regulation, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION

Enbridge grants stock-based compensation to certain employees and senior officers of the Company through four long-term incentive compensation plans. Compensation expense associated with each of the plans, as determined under the methods outlined below is recognized in Operating and administrative expense. Amounts owing to Enbridge in respect of stock-based compensation are payable on a quarterly basis.

Incentive Stock Options (ISOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISOs granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility.

Performance based stock options (PBSOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the PBSOs granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting. The options become exercisable when both performance targets and time vesting requirements have been met.

Performance Stock Units (PSUs) and Restricted Stock Units (RSUs) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of the Company's shares . The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

COMPARATIVE AMOUNTS

Certain comparative amounts have been reclassified to conform with the current year's consolidated financial statement presentation.

3. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

ADOPTION OF NEW STANDARDS

Balance Sheet Offsetting

Effective January 1, 2013, the Company adopted Accounting Standards Update (ASU) 2011-11 and ASU 2013-01, which require enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. As the adoption of these updates impacted disclosure only, there was no impact to the Company's consolidated financial position for the current or prior periods presented.

Accumulated Other Comprehensive Income

Effective January 1, 2013, the Company adopted ASU 2013-02, which requires enhanced disclosures on amounts reclassified out of AOCI. As the adoption of this update impacted disclosure only, there was no impact to the Company's consolidated financial statements for the current or prior periods presented.

Presentation of Unrecognized Tax Benefits

Effective December 31, 2013, the Company elected to early adopt ASU 2013-11 which requires presentation of unrecognized tax benefits as a reduction to a deferred tax asset for a net operating loss carryforward unless specific conditions exist. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Obligations Resulting from Joint and Several Liability Arrangements

ASU 2013-04 was issued in February 2013 and provides both measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied retrospectively.

Parent's Accounting for the Cumulative Translation Adjustment

ASU 2013-05 was issued in March 2013 and provides guidance on the timing of release of the cumulative translation adjustment into net income when a disposition or ownership change occurs related to an investment in a foreign entity or a business within a foreign entity. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied prospectively.

CHANGES IN ACCOUNTING ESTIMATES

Depreciation Rates

In 2013, the Company revised depreciation rates based on the results of a new depreciation study which was approved by the OEB as part of the cost of service settlement applicable to 2013. Had rates remained the same, depreciation and amortization expense would have been higher by $32 million for the year ended December 31, 2013.

4. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

In connection with the preparation of the Company's consolidated financial statements for the nine months ended September 30, 2013, an error was identified in the manner in which a component of gas commodity and distribution costs had been recorded. The matter related to the accounting true-up mechanism between actual gas commodity and distribution costs incurred and the regulator-approved price charged to customers.

In accordance with accounting guidance found in Accounting Standards Codification (ASC) 250-10 (Securities and Exchange Commission (SEC) Staff Accounting Bulletin No. 99, *Materiality*), the Company assessed the materiality of the error and concluded that it was not material to any of the Company's previously issued consolidated financial statements. In accordance with guidance found in ASC 250-10 (SEC Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*), the Company revised its comparative consolidated financial statements to correct the effect of this matter. As a result of this error, the Company remitted excess income taxes totaling $22 million to the Canada Revenue Agency (CRA) in relation to the 2010, 2011 and 2012 taxation years and over shared earnings with ratepayers under an earnings sharing mechanism in relation to 2010, 2011 and 2012. The Company expects that it will recover the tax overpayment from the CRA.

The following tables present the effect of this correction on individual line items within the Company's Consolidated Statements of Earnings and Consolidated Statements of Financial Position. The effects which flow through to the individual line items of Earnings, Gas commodity and distribution costs excluding depreciation, Income taxes, Gas inventories, Accounts receivable and other, Accounts payable and other, and Changes in operating assets and liabilities of the Consolidated Statements of Cash Flows are not significant and have no net effect on the Company's cash flows from operating activities. Comparative figures as at December 31, 2012 and for the years ended December 31, 2012 and 2011 have been revised throughout these financial statements as necessary to reflect these revisions.

	Year ended December 31, 2012			Year ended December 31, 2011		
	As Previously Reported	Adjustment	As Revised	As Previously Reported	Adjustment	As Revised
(millions of Canadian dollars)						
Gas commodity and distribution costs excluding depreciation	(1,199)	(30)	(1,229)	(1,268)	(28)	(1,296)
Income tax expense - current	(41)	8	(33)	(52)	8	(44)
Earnings from continuing operations	230	(22)	208	191	(20)	171
Earnings	234	(22)	212	193	(20)	173
Earnings attributable to the common shareholder	232	(22)	210	191	(20)	171

	December 31, 2012		
	As Previously Reported	Adjustment	As Revised
(millions of Canadian dollars)			
Accounts receivable and other	594	11	605
Gas inventories	326	15	341
Accounts payable and other	648	82	730
Retained earnings	63	(56)	7

5. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

For the purposes of this note, “Enbridge Gas Distribution” refers specifically to Enbridge Gas Distribution Inc. excluding St. Lawrence, whereas “St. Lawrence” refers specifically to St. Lawrence Gas Company, Inc.

RATE APPROVAL

For the year ended December 31, 2013, Enbridge Gas Distribution’s rates were set pursuant to an OEB approved settlement agreement and decision related to its 2013 cost of service rate application. For the years ended December 31, 2013, 2012 and 2011, St. Lawrence’s rates were set using a cost of service (COS) methodology. Under COS, revenues are set to recover costs and to earn a rate of return on the deemed common equity component of rate base. Costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, municipal and other taxes, interest and income taxes. Rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under COS, it is the responsibility of Enbridge Gas Distribution and St. Lawrence to demonstrate to the Regulators the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken.

For the years ended December 31, 2012 and 2011, Enbridge Gas Distribution’s annual rates were set using a revenue per customer cap Incentive Regulation (IR) methodology which adjusted revenues, and consequently rates, annually and relied on an annual process to forecast volume and customer additions. Under the IR mechanism, Enbridge Gas Distribution was allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps was required to be shared with customers on an equal basis.

In July 2013, Enbridge Gas Distribution filed an application with the OEB for the setting of rates through a customized IR mechanism for the period of 2014 through 2018. A decision is anticipated in the second quarter of 2014.

The cost of natural gas is passed on to customers as a flow-through.

APPROVED RATES

Enbridge Gas Distribution

Enbridge Gas Distribution’s rates for 2013 included an after-tax rate of return on common equity of 8.93% (2012 and 2011 - 8.39%) based on a 36% (2012 and 2011 - 36%) deemed common equity component of rate base. The earnings sharing mechanism, which was previously in effect under the IR methodology, did not apply in 2013.

St. Lawrence

St. Lawrence’s approved after-tax rate of return on common equity embedded in rates was 10.5% for the year ended December 31, 2013 (2012 - 10.5%) based on a 50% (2012 - 50%) deemed common equity component of rate base. Any earnings above a return on equity of 11% (2012 - 11%) were shared equally with customers. The calculation of such earnings was cumulative from January 1, 2010 to December 31, 2013 and resulted in no sharing impact as at December 31, 2013 (2012 - nil).

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities

As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement
The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. The Regulators' future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

FINANCIAL STATEMENT EFFECTS
As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	**2013**	2012	Consolidated Statement of Financial Position Location**	Estimated Recovery/ Settlement Period *(years)*
(millions of Canadian dollars)				
Regulatory assets/(liabilities)				
Enbridge Gas Distribution				
Deferred income taxes[1]	**209**	198	DA	*
OPEB[2]	**89**	89	AR/DA	19
Shared savings mechanism[3]	**16**	-	AR	*
Average use true-up variance[4]	**10**	4	AR	*
Unaccounted for gas variance[5]	**8**	2	AR	1
Customer care CIS rate smoothing deferral[6]	**5**	-	DA	5
Deferred rate hearing costs[7]	**4**	5	AP/DA	2
Post-retirement true-up variance[8]	**3**	-	AR	1
Pension plans, net[9]	**2**	115	DA/OLTL	*
Future removal and site restoration reserves[10]	**(905)**	(859)	OLTL	*
Transactional services deferral[11]	**(51)**	(26)	AP	1
Earnings sharing deferral[12]	**(7)**	(10)	AP	*
Purchased gas variance[13]	**(6)**	(82)	AP	1
Storage and transportation deferral[14]	**(3)**	(1)	AP	1
Other regulatory assets and liabilities	**1**	4	***	***
	(625)	(561)		
St. Lawrence				
Other regulatory assets and liabilities	**(1)**	8	***	***
	(1)	8		
	(626)	(553)		

* Refer to the footnote for details
** AR – Accounts receivable and other
AP – Accounts payable and other
DA – Deferred amounts and other assets
OLTL – Other long-term liabilities
*** Dependent on the nature of the item

1 *The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

2 *The OPEB balance represents the Company's right to recover OPEB costs pursuant to an OEB rate order, which allows the amount to be collected in rates over a 20-year period commencing in 2013. In the absence of rate regulation, this regulatory balance and related earnings impact would not be recorded.*

3 *Shared Savings Mechanism (SSM) deferral represents the benefit derived by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the SSM amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation.*

4 *Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual weather normalized average use for general service customers. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

5 *Unaccounted for gas variance represents the difference between the total natural gas distributed by Enbridge Gas Distribution and the amount of natural gas billed or billable to customers for their recorded consumption, to the extent it is different from the approved amount built into rates. Enbridge Gas Distribution has deferred unaccounted for gas variance and has historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation, this variance would be included in earnings in the year incurred.*

6 *Customer care CIS rate smoothing deferral represents the difference between the forecast costs and the approved costs for customer care and CIS reflected in rates. The balance will accumulate during 2013 to 2015 when the cost per customer exceeds the cost approved for recovery in rates. The balance will be drawn down during 2016 to 2018 when the cost per customer is lower than the cost approved for recovery in rates. Enbridge Gas Distribution has received OEB approval to collect from or refund to customers any remaining balance after 2018. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

7 *Deferred rate hearing costs are incurred by Enbridge Gas Distribution for the regulatory process. Enbridge Gas Distribution has historically been granted OEB approval for recovery of such hearing costs, generally within two years. In the absence of rate regulation, these costs would be expensed as incurred.*

8 *Post-retirement true-up variance is the difference between the actual cost and the approved cost of pension and OPEB reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers in the subsequent year, up to a maximum of $5 million per year. Any amounts in excess of $5 million per year will be deferred for refund or collection in the next subsequent year. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

9 *The pension plan balance represents the regulatory offset to the pension liability/asset to the extent the amounts are to be collected/refunded in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

10 *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

11 *Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.*

12 *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the IR Settlement applicable to 2012. The earnings sharing is payable to customers and represented 50% of normalized 2012 Canadian GAAP earnings represented by the ROE in excess of 100 basis points above the allowed utility return on equity threshold applicable to Enbridge Gas Distribution under IR. The December 31, 2012 balance related to the year ended December 31, 2012. Earnings sharing did not apply to the 2013 COS Settlement. There would be no change in the treatment of this item in the absence of rate regulation.*

13 *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In the absence of rate regulation, the actual cost of natural gas would be included in gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established. Purchased gas variance for 2012 has been revised as per Note 4.*

14 *Storage and transportation deferral represents the difference between the actual cost and the approved cost of natural gas storage and transportation reflected in rates. Enbridge Gas Distribution has historically been granted OEB approval to collect this balance from or to refund this balance to customers, generally in the subsequent year. In the absence of rate regulation, the actual cost of natural gas storage and transportation would be included in gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount, as the right to collect or refund the revenue or costs has been established.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Revenue

To recognize the actions or expected actions of the Regulators, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

In 2012, the Company received a rate order from the OEB permitting recovery of OPEB costs in the amount of $89 million. The rate order allows this amount to be collected in rates over a 20-year period commencing in 2013, and was presented in Other revenue for the year ended December 31, 2012. In the absence of rate regulation, this earnings impact would not have been recorded.

Operating Cost Capitalization

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2013, cumulative costs relating to this services contract of $154 million (2012 - $144 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment

In the absence of rate regulation, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred. Further, on the retirement of utility assets, the excess of the book value net of proceeds would be recorded as a loss on the sale of assets in earnings in the period of retirement. Any removal costs incurred would be booked against the future removal and site restoration balance (described above).

Intangible Assets

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2013, the net book value of these costs was $73 million (2012 - $86 million). In the absence of rate regulation, a portion of the original cost of these assets would have been expensed in the period incurred.

Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. Included in gas inventories at December 31, 2013 is $40 million (2012 - $39 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation, these costs would be expensed as incurred and inventory would be recorded at the lower of cost or market value.

Depreciation

In the absence of rate regulation, depreciation rates would not have included a charge for future removal and site restoration costs.

6. DISCONTINUED OPERATIONS

In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to Enbridge Income Fund (the Fund), an affiliated entity under common control, for proceeds of $72 million. Project Amherstburg consisted primarily of property, plant and equipment and intangible assets. The excess of the sale price over the net book value at the time of disposition of $17 million inclusive of deferred income tax recoveries of $10 million were recognized as Additional paid-in capital. No gain or loss was recognized in earnings on the disposition; however $5 million of cash income taxes incurred on the related capital gain remains as a charge to consolidated earnings for the year ended December 31, 2012.

In 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company. The total consideration transferred for Project Amherstburg was approximately $66 million, which was primarily funded by the issuance of common shares (1,612,367 shares).

7. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2013**	2012
(millions of Canadian dollars)		
Trade receivables	**357**	321
Unbilled revenues	**211**	170
Regulatory assets *(Note 5)*	**54**	21
Short-term portion of derivative assets *(Note 17)*	**36**	-
Agent billing and collection receivable	**15**	44
Due from affiliates *(Note 21)*	**13**	12
Taxes receivable	**9**	40
Prepaid expenses	**7**	4
Current deferred income taxes *(Note 18)*	**2**	5
Other	**33**	29
Allowance for doubtful accounts	**(31)**	(41)
	706	605

8. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2013**	2012
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	**3.1%**	**3,342**	3,132
Gas services	**3.0%**	**2,667**	2,530
Regulating and metering equipment	**6.0%**	**781**	757
Gas storage	**2.4%**	**314**	295
Land and right-of-way	**1.1%**	**71**	70
Computer technology	**37.2%**	**36**	42
Under construction	**-**	**198**	102
Construction materials inventory	**-**	**35**	38
Other	**7.5%**	**280**	274
		7,724	7,240
Accumulated depreciation		**(1,949)**	(1,798)
		5,775	5,442
Unregulated property, plant and equipment			
Gas storage	**2.2%**	**87**	86
Other	**1.6%**	**24**	18
		111	104
Accumulated depreciation		**(17)**	(14)
		94	90
Property, plant and equipment, net		**5,869**	5,532

Depreciation expense, including amounts collected for future removal and site restoration costs, was $267 million for the year ended December 31, 2013 (2012 - $289 million, 2011 - $271 million).

9. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2013**	2012
(millions of Canadian dollars)		
Regulatory assets *(Note 5)*	**312**	414
Long-term portion of derivative assets *(Note 17)*	**46**	1
Deferred financing costs	**11**	11
Pension and OPEB asset *(Note 19)*	**8**	3
Other	**2**	3
	379	432

At December 31, 2013, deferred amounts of $31 million (2012 - $29 million) were subject to amortization and are presented net of accumulated amortization of $20 million (2012 - $18 million). Amortization expense for the year ended December 31, 2013 was $2 million (2012 - $2 million, 2011 - $2 million).

10. INTANGIBLE ASSETS

December 31, 2013	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**22.8%**	**162**	**(61)**	**101**
CIS	**10%**	**127**	**(54)**	**73**
		289	**(115)**	**174**

December 31, 2012	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	20.6%	128	(37)	91
CIS	10.0%	127	(41)	86
		255	(78)	177

Intangible assets include $19 million of work-in-progress as at December 31, 2013 (2012 - $33 million). Total amortization expense for intangible assets was $37 million for the year ended December 31, 2013 (2012 - $31 million, 2011 - $31 million). The Company expects aggregate amortization expense for the years ending December 31, 2014 through 2018 of $41 million, $43 million, $49 million, $47 million and $45 million, respectively.

11. ACCOUNTS PAYABLE AND OTHER

December 31,	**2013**	2012
(millions of Canadian dollars)		
Operating accrued liabilities	**329**	279
Budget billing plan payable	**82**	59
Regulatory liabilities *(Note 5)*	**76**	121
Security deposits	**62**	67
Dividends payable	**51**	51
Due to affiliates *(Note 21)*	**49**	10
Trade payables	**46**	59
Interest payable	**28**	26
Taxes payable	**22**	28
Current portion of OPEB liability *(Note 19)*	**4**	5
Other	**20**	25
	769	730

12. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2013**	2012
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	85
Medium term notes	5.33%	2014-2050	**2,695**	2,295
Commercial paper and credit facility draws, net			**382**	590
Other[1]			**26**	13
Total debt			**3,188**	2,983
Current maturities			**(400)**	-
Short-term borrowings	1.13%		**(389)**	(596)
Long-term debt			**2,399**	2,387
Loans from affiliate company *(Note 21)*			**375**	375

1 *Consists of note payable to affiliate company and debt premium*

For the years ending December 31, 2014 through 2018, medium-term note maturities are $400 million, $1 million, $2 million, $201 million and $2 million, respectively. The Company's debentures and medium term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2014 through 2018 are $146 million, $130 million, $130 million, $130 million and $120 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Debentures and medium-term notes	**138**	139	140
Loans from affiliate company *(Note 21)*	**27**	27	27
Commercial paper and credit facility draws	**4**	2	3
Other interest and finance costs	**9**	8	8
Capitalized	**(7)**	(6)	(6)
	171	170	172

In 2013, total interest paid to third parties was $142 million (2012 - $142 million, 2011 - $149 million) and total interest paid to affiliate company was $27 million (2012 - $34 million, 2011 - $20 million).

CREDIT FACILITIES

The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option. In August 2013, the Company extended the term out date of its $700 million committed line of credit for an additional year to August 2014, with a maturity date in August 2015.

December 31, 2013	Maturity Dates	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc.	2015	**700**	**370**	**330**
St. Lawrence Gas Company, Inc.	2019	**13**	**12**	**1**
Total credit facilities		**713**	**382**	**331**

1 *Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the credit facility.*

Credit facilities carried a weighted average standby fee of 0.2% on the unused portion and draws bear interest at market rates.

The Company's borrowings, whether debentures or medium-term notes, are unsecured. When issuing any new indebtedness with a maturity over 18 months, covenants contained in the Company's trust indenture require the pro forma long-term debt interest coverage ratio be at least 2.0 times for 12 consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as U.S. GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of financing costs and intercompany interest expense less gains on asset dispositions divided by the annual interest requirement. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. As at December 31, 2013, the Company was in compliance with this covenant.

13. OTHER LONG-TERM LIABILITIES

December 31,	**2013**	2012
(millions of Canadian dollars)		
Regulatory liabilities *(Note 5)*	**916**	867
Pension and OPEB liabilities *(Note 19)*	**104**	226
Other	**6**	1
	1,026	1,094

14. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preference shares.

COMMON SHARES

	2013		2012		2011	
December 31,	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**142.3**	**1,137**	142.3	1,137	140.7	1,071
Common shares issued	**8.3**	**150**	-	-	1.6	66
Balance at end of year	**150.6**	**1,287**	142.3	1,137	142.3	1,137

PREFERENCE SHARES

December 31, 2013, 2012, and 2011	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preference shares in millions)			
Group 1	0.2	-	-
Group 2, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 2, Series D, Cumulative Redeemable Convertible	4	-	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	-	-
Group 5	10	-	-
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preference shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case. As at December 31, 2013, no preference shares have been redeemed.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference shares on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preference shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

15. STOCK OPTION AND STOCK UNIT PLANS

Enbridge's four long-term incentive compensation plans include the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. The Company reimburses Enbridge for stock-based compensation costs associated with its employees on a quarterly basis.

INCENTIVE STOCK OPTIONS

Key employees of the Company are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2013	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**2,527**	**24.88**		
Options granted	**456**	**44.81**		
Options exercised[1]	**(264)**	**16.93**		
Options cancelled	**(229)**	**30.97**		
Options outstanding at end of year	**2,490**	**28.81**	**6.2**	**40**
Options vested at end of year[2]	**1,430**	**22.12**	**4.7**	**33**

1 *The total intrinsic value of ISOs exercised during the year ended December 31, 2013 was $7 million (2012 - $11 million; 2011 - $8 million) and cash received by Enbridge on exercise was $2 million (2012 - $6 million; 2011 - $7 million).*

2 *The total fair value of options vested under the ISO Plan during the year ended December 31, 2013 was $2 million (2012 - $2 million; 2011 - $1 million).*

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2013**	2012	2011
Fair value per option *(Canadian dollars)*[1]	**5.27**	4.81	4.19
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	6
Expected volatility[3]	**17.4%**	19.7%	18.6 %
Expected dividend yield[4]	**2.8%**	3.0%	3.4%
Risk-free interest rate[5]	**1.2%**	1.3%	2.9%

1 *Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $5.15 (2012 - $4.65; 2011 - $4.01) for Canadian employees and US$5.63 (2012 - US$5.58, 2011 - US$5.11) for United States employees.*

2 *The expected option term is based on historical exercise practice.*

3 *Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.*

4 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*

5 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.*

Compensation expense recorded for the year ended December 31, 2013 for ISOs was $3 million (2012 - $3 million, 2011 - $3 million). At December 31, 2013, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $3 million. The cost is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted by Enbridge to executive officers of the Company and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on August 15, 2012 under the 2007 plan. Time vesting requirements for the 2012 grant will be fulfilled evenly over a five-year term, ending August 15, 2017. The 2012 grant's performance targets are based on Enbridge's share price and must be met by February 15, 2019 or the options expire. If targets are met by February 15, 2019, the options are exercisable until August 15, 2020.

December 31, 2013	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**169**	**39.34**		
Options cancelled	**(169)**	**39.34**		
Options outstanding at end of year	**-**	**-**	**-**	**-**

Weighted average assumptions used to determine the fair value of the PBSOs using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	**2013**
Fair value per option *(Canadian dollars)*	**4.25**
Valuation assumptions	
Expected option term *(years)*[1]	**8**
Expected volatility[2]	**16.1%**
Expected dividend yield[3]	**2.8%**
Risk-free interest rate[4]	**1.6%**

1 *The expected option term is based on historical exercise practice.*
2 *Expected volatility is determined with reference to historic daily share price volatility.*
3 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*
4 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields.*

Compensation expense for PBSOs was nil for the years ended December 31, 2013, 2012, and 2011. At December 31, 2013, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the PBSO Plan was $1 million. The cost is expected to be fully recognized over a weighted average period of approximately four years.

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan for senior officers of the Company where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two if Enbridge performs within the highest range of its performance targets. The 2011, 2012 and 2013 grants derive the performance multiplier through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's earnings per share, adjusted for unusual non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2013 expense, multipliers of two, based upon multiplier estimates at December 31, 2013, were used for each of the 2011, 2012 and 2013 PSU grants.

December 31, 2013	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**36**		
Units granted	**10**		
Units cancelled	**(7)**		
Units matured[1]	**(21)**		
Dividend reinvestment	**1**		
Units outstanding at end of year	**19**	**1.5**	**2**

1 The total amount paid by Enbridge during the year ended December 31, 2013 for PSUs was $2 million (2012 - $1 million; 2011 - $1 million).

Compensation expense recorded for the year ended December 31, 2013 for PSUs was $4 million (2012 - $7 million; 2011 - $6 million). As of December 31, 2013, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $1 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a RSU Plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2013	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**228**		
Units granted	**94**		
Units cancelled	**(1)**		
Units matured[1]	**(127)**		
Dividend reinvestment	**9**		
Units outstanding at end of year	**203**	**1.4**	**9**

1 The total amount paid by Enbridge during the year ended December 31, 2013 for RSUs was $5 million (2012 - $5 million; 2011 - $5 million).

Compensation expense recorded for the year ended December 31, 2013 for RSUs was $5 million (2012 - $5 million; 2011 - $5 million). As of December 31, 2013, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $5 million and is expected to be fully recognized over a weighted average period of approximately two years.

16. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in AOCI for the years ended December 31, 2013, 2012 and 2011, are as follows:

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(*millions of Canadian dollars*)				
Balance at January 1, 2013	**(10)**	**(6)**	**(10)**	**(26)**
Other comprehensive income retained in AOCI	**109**	**1**	**14**	**124**
Other comprehensive income reclassified to earnings				
Interest rate contracts[1]	**(1)**	**-**	**-**	**(1)**
	108	**1**	**14**	**123**
Tax impact				
Income tax on amounts retained in AOCI	**(28)**	**-**	**(4)**	**(32)**
	(28)	**-**	**(4)**	**(32)**
Balance at December 31, 2013	**70**	**(5)**	**-**	**65**

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(*millions of Canadian dollars*)				
Balance at January 1, 2012	(11)	(6)	(7)	(24)
Other comprehensive loss retained in AOCI	(1)	-	(4)	(5)
Other comprehensive loss reclassified to earnings				
Interest rate contracts[1]	2	-	-	2
	1	-	(4)	(3)
Tax impact				
Income tax on amounts retained in AOCI	-	-	1	1
	-	-	1	1
Balance at December 31, 2012	(10)	(6)	(10)	(26)

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(*millions of Canadian dollars*)				
Balance at January 1, 2011	(12)	(6)	3	(15)
Other comprehensive income retained in AOCI	(2)	-	(13)	(15)
Other comprehensive loss reclassified to earnings				
Interest rate contracts[1]	3	-	-	3
	1	-	(13)	(12)
Tax impact				
Income tax on amounts retained in AOCI	1	-	3	4
Income tax on amounts reclassified to earnings	(1)	-	-	(1)
	-	-	3	3
Balance at December 31, 2011	(11)	(6)	(7)	(24)

1 *Reported within Interest expense in the Consolidated Statements of Earnings.*

17. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

MARKET PRICE RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates and natural gas prices (collectively, market price risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations in the exchange rate of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is nil (2012 - nil).

Interest Rate Risk
The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to mitigate the volatility of short-term interest rates on interest expense related to variable rate debt.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances. The Company uses qualifying derivative instruments to manage interest rate risk.

Natural Gas Price Risk
Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer, therefore, the net exposure to the Company is nil (2012 - nil).

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges at December 31, 2013 or 2012.

The Company generally has a policy of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2013	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts receivable and other					
Interest rate contracts	**36**	**-**	**36**	**-**	**36**
Deferred amounts and other assets					
Interest rate contracts	**46**	**-**	**46**	**-**	**46**
Total net derivative asset					
Interest rate contracts	**82**	**-**	**82**	**-**	**82**

December 31, 2012	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Deferred amounts and other assets					
Interest rate contracts	1	-	1	-	1
Accounts payable and other					
Interest rate contracts	(1)	-	(1)	-	(1)
Other long-term liabilities					
Interest rate contracts	(1)	-	(1)	-	(1)
Total net derivative liability					
Interest rate contracts	(1)	-	(1)	-	(1)

The Company's derivatives instruments mature through 2017 and have a notional principal of $535 million for interest rate contracts for short-term borrowings (2012 - $673 million), and $747 million for interest rate contracts on long-term debt (2012 - $1,007 million).

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Interest rate contracts	**109**	(1)	(2)
	109	(1)	(2)
Amount of loss reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**(2)**	(2)	(3)
	(2)	(2)	(3)
Amount of gains reclassified from AOCI to earnings *(ineffective portion)*			
Interest rate contracts[1]	**2**	-	-
	2	-	-

1 Reported within Interest expense in the Consolidated Statements of Earnings.

The Company estimates that $2 million in AOCI related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 37 months at December 31, 2013.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 21 and 22)* as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains a current shelf prospectus with securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 12)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2013. As a result, all credit facilities are available to the Company and the banks are obligated to fund, and have been funding, the Company under the terms of the facilities.

CREDIT RISK
The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts.

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate.

Entering into derivative financial instruments may also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

The Company had group credit concentration and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments:

	December 31, 2013	December 31, 2012
(millions of Canadian dollars)		
Canadian financial institutions	**69**	1
European financial institutions	**13**	-
	82	1

FAIR VALUE MEASUREMENTS
The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

Fair Value of Derivatives
The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1
Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is

considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company does not have any derivative instruments classified as Level 1.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps for which observable inputs can be obtained.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2013, the Company had Level 2 derivative assets with fair value of $82 million (2012 - $1 million), and Level 2 derivative liabilities with fair value of nil (2012 - $2 million).

The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at December 31, 2013 or 2012.

Fair Value of Other Financial Instruments

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted market prices are not available for fair value measurement in which case these investments are recorded at cost. The Company's investment in IPL System Inc., an affiliate company, is carried at cost of $825 million at December 31, 2013 (2012 - $825 million), which approximates its fair value and redemption value.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2013, the Company's long-term debt had a carrying value of $2,799 million (2012 - $2,387 million) and a fair value of $3,161 million (2012 - $2,994 million).

The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity.

18. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations	**260**	261	206
Federal statutory income tax rate	**15.0%**	15.0%	16.5%
Federal income taxes at statutory rate	**39**	39	34
Increase/(decrease) resulting from:			
Provincial and state income taxes	**19**	18	16
Effects of rate regulated accounting	**(5)**	(7)	-
Non-taxable intercompany distributions	**(9)**	(9)	(10)
Legislative changes and other rate differentials	**-**	8	-
Intercompany sale of investment[1]	**-**	3	-
Other[2]	**(1)**	1	(5)
Income taxes before discontinued operations	**43**	53	35
Effective income tax rate	**16.5%**	20.3%	17.0%

1 In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund. As the transaction occurred between entities under common control of Enbridge, the intercompany gain realized as a result of this transfer was eliminated, although cash income taxes of $5 million remained as a charge to earnings.

2 Included in "Other" are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals & entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.

Comparative figures within the income tax reconciliation for 2012 and 2011 have been revised to conform to the presentation followed for the current year. In 2013, a preferable presentation format was adopted which calculates expected taxes using a federal statutory rate as opposed to a combined federal and provincial rate. This format is preferable as it is more commonly used by companies following U.S. GAAP.

COMPONENTS OF DEFERRED INCOME TAXES
Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2013**	2012
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(320)**	(317)
Financial derivatives	**(25)**	-
Deferrals	**(13)**	(23)
Regulatory assets	**(56)**	(52)
Other	**(2)**	-
Total deferred income tax liabilities	**(416)**	(392)
Deferred income tax assets		
Financial derivatives	**-**	4
Retirement and postretirement benefits	**23**	23
Other	**1**	8
Total deferred income tax assets	**24**	35
Net deferred income tax liabilities	**(392)**	(357)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 7)*	**2**	5
Deferred amounts and other assets *(Note 9)*	**1**	-
Total deferred income tax assets	**3**	5
Liabilities		
Deferred income taxes	**(395)**	(362)
Total deferred income tax liabilities	**(395)**	(362)
Net deferred income tax liabilities	**(392)**	(357)

The Company has assessed all tax positions. As a result, no significant adjustments were required to be made to the income tax provisions for the year ended December 31, 2013.

The Company and its subsidiaries are subject to taxation in Canada. The Company is open to examination by certain tax authorities for the 2009 to 2013 tax years. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario).

19. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS
The Company maintains a non-contributory basic pension plan that provides either defined benefit or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees.

A measurement date of December 31, 2013 was used to determine the plan assets and accrued benefit obligation for the pension plans.

Defined Benefit Plans
Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. In 2013, mortality assumptions were revised resulting in an increase to pension liabilities of $28 million. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective date of the most recent actuarial valuation was September 1, 2013. The effective date of the next required actuarial valuation is September 1, 2016.

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

OTHER POSTRETIREMENT BENEFITS

The Company also provides OPEB, which primarily includes supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension		OPEB	
December 31,	**2013**	2012	**2013**	2012
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**905**	852	**112**	103
Service cost	**25**	21	**1**	2
Interest cost	**38**	37	**4**	4
Actuarial loss	**(52)**	33	**(16)**	5
Benefits paid	**(40)**	(37)	**(2)**	(3)
Other	**(1)**	(1)	**1**	1
Benefit obligation at end of year	**875**	905	**100**	112
Change in plan assets				
Fair value of plan assets at beginning of year	**782**	744	**7**	6
Actual return on plan assets	**84**	59	**1**	1
Employer's contributions	**38**	17	**3**	4
Benefits paid	**(40)**	(37)	**(2)**	(3)
Other	**2**	(1)	**-**	(1)
Fair value of plan assets at end of year	**866**	782	**9**	7
Underfunded status at end of year	**(9)**	(123)	**(91)**	(105)
Presented as follows:				
Deferred amounts and other assets *(Note 9)*	**7**	3	**1**	-
Accounts payable and other *(Note 11)*	**-**	-	**(4)**	(5)
Other long-term liabilities *(Note 13)*	**(16)**	(126)	**(88)**	(100)

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2013**	2012	2011	**2013**	2012	2011
Discount rate	**5.0%**	4.3%	4.5%	**5.0%**	4.3%	4.5%
Average rate of salary increases	**3.5%**	3.5%	3.5%	**3.5%**	3.5%	5.0%

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2013**	2012	2011	**2013**	2012	2011
(millions of Canadian dollars)						
Benefits earned during the year	**25**	21	16	**1**	2	1
Interest cost on projected benefit obligations	**38**	37	39	**4**	4	5
Actual return on plan assets	**(84)**	(59)	(15)	**(1)**	(1)	-
Actuarial loss	**(52)**	33	127	**(16)**	5	13
Difference between actual and expected return on plan assets						
Return on plan assets	**32**	10	(38)	**-**	-	-
Amortization of prior service costs	**1**	1	2	**-**	-	-
Amortization of actuarial loss	**80**	(3)	(110)	**18**	(4)	(13)
Net defined benefit costs on an accrual basis	**40**	40	21	**6**	6	6
Defined contribution benefit costs	**1**	1	1	**-**	-	-
Net benefit cost recognized on an accrual basis	**41**	41	22	**6**	6	6
Net amount recognized in OCI						
Net actuarial (gain)/loss[1]	**-**	-	-	**(14)**	4	13
Total amount recognized in OCI	**-**	-	-	**(14)**	4	13
Total net benefit cost on an accrual basis and amount recognized in OCI	**41**	41	22	**(8)**	10	19

1 *Unamortized actuarial losses included in AOCI, before tax, were nil relating to OPEB at December 31, 2013 (2012 - $14 million, 2011 - $10 million).*

The Company estimates that approximately $17 million related to pension plans and OPEB at December 31, 2013 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Prior service costs	**-**	**-**	**-**
Actuarial Loss	**17**	**-**	**17**
	17	**-**	**17**

Regulatory adjustments were recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers in future rates *(Note 5)*. For the year ended December 31, 2013, an offsetting regulatory asset of $3 million (2012 - $22 million) has been recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.

Pension and OPEB costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension and OPEB costs due to the regulatory mechanism in place. As a result, the net pension and OPEB expense primarily consisted of OEB approved pension and OPEB costs.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2013**	2012	2011	**2013**	2012	2011
Discount rate	**4.3%**	4.5%	5.7%	**4.3%**	4.5%	5.7%
Average rate of return on pension plan assets	**6.8%**	7.0%	7.3%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.5%**	3.5%	3.5%	**3.5%**	5.0%	5.0%

MEDICAL COST TRENDS
The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in Which Ultimate Medical Cost Trend Rate Assumption is Achieved
Drugs	8.2%	4.3%	2029
Other medical and dental	4.5%	4.5%	-

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $12 million in the benefit obligation and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $10 million in the benefit obligation and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS
The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2013**	2012	**2013**	2012
Expected rate of return	**6.8%**	7.0%	**-**	-

Target Mix for Plan Assets

Equity securities	44.5%
Fixed income securities	40.0%
Other	15.5%

Major Categories of Plan Assets
Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2013, the pension assets were invested in 55% (2012 - 60%) in equity securities, 36% (2012 - 37%) in fixed income securities and 9% (2012 - 3%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $18 million (2012 - $10 million) have been excluded from the table below.

	2013				2012			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension Benefits								
Cash and cash equivalents	**12**	**-**	**-**	**12**	18	-	-	18
Fixed income securities								
Canadian government real return bonds	**62**	**-**	**-**	**62**	57	-	-	57
Canadian corporate bond index fund	**122**	**-**	**-**	**122**	109	5	-	114
Canadian government bond index fund	**115**	**-**	**-**	**115**	109	-	-	109
Canadian real return bond index fund	**2**	**-**	**-**	**2**	-	2	-	2
Corporate bonds and debentures	**3**	**-**	**-**	**3**	-	-	-	-
United States debt index fund	**1**	**-**	**-**	**1**	-	-	-	-
Equity								
Canadian equity securities	**70**	**-**	**-**	**70**	113	-	-	113
Canadian equity funds	**118**	**-**	**-**	**118**	4	59	-	63
United States equity securities	**1**	**-**	**-**	**1**	-	-	-	-
United States equity funds	**65**	**17**	**-**	**82**	58	13	-	71
Global equity funds	**142**	**55**	**-**	**197**	100	74	-	174
Infrastructure [4]	**-**	**-**	**29**	**29**	-	-	38	38
Real estate[5]	**-**	**-**	**38**	**38**	-	-	15	15
Forward currency contracts	**-**	**(4)**	**-**	**(4)**	-	(2)	-	(2)
OPEB								
Cash and cash equivalents	**-**	**-**	**-**	**-**	1	-	-	1
Fixed income securities								
United States government and government agency bonds	**3**	**-**	**-**	**3**	2	-	-	2
Equity								
United States equity fund	**3**	**-**	**-**	**3**	2	2	-	4
Global equity fund	**3**	**-**	**-**	**3**	-	-	-	-

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair value of the investment in United States Limited Partnership - Global Infrastructure Fund is established through the use of valuation models.
5 The fair value of the investment in Bentall Kennedy Prime Canadian Property Fund Ltd is established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2013**	2012
Balance at beginning of year	**53**	44
Unrealized and realized gains	**4**	7
Purchases and settlements, net	**10**	2
Balance at end of year	**67**	53

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension		OPEB	
Year ended December 31,	**2013**	2012	**2013**	2012
(millions of Canadian dollars)				
Total contributions	**39**	18	**3**	4
Contributions expected to be paid in 2014	**56**		**5**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2014	2015	2016	2017	2018	2019-2023
(millions of Canadian dollars)						
Expected future benefit payments	44	46	48	50	52	285

20. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Accounts receivable and other	**(46)**	76	134
Gas inventories	**(41)**	54	11
Accounts payable and other	**35**	(32)	(103)
Other long-term liabilities[1]	**(34)**	(27)	(27)
	(86)	71	15

1 *Consists primarily of net costs for site removal and restoration activities.*

21. RELATED PARTY TRANSACTIONS

All related party transactions, other than those disclosed under Other Transactions, are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
IPL System Inc.			
Dividend income	**63**	63	63
Interest expense	**27**	27	27
Enbridge			
Purchase of treasury and other management services	**38**	39	34
Tidal Energy Marketing Inc.			
Purchase of natural gas	**30**	11	17
Tidal Energy Marketing (U.S.) LLC			
Purchase of natural gas	**21**	2	2
Gazifère Inc.			
Revenue from wholesale service, including gas sales	**30**	25	28
Vector Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**24**	24	24
Vector Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**2**	2	2
Alliance Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**26**	25	25
Alliance Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**19**	18	18

The Company had related party balances as follows:

December 31,	**2013**	2012
(millions of Canadian dollars)		
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**2**	2
Note payable to affiliate company		
Enbridge (U.S.)	**15**	13
Other accounts receivable/(payable)		
Enbridge Pipelines Inc.	**(15)**	3
IPL System Inc.	**(15)**	-
Tidal Energy Marketing (U.S.) LLC	**(4)**	-
Enbridge	**(5)**	(7)
Tidal Energy Marketing Inc.	**(7)**	(2)
Gazifère Inc.	**5**	4

Financing Transactions
The Company has invested in Class D, non-voting, redeemable, retractable preferred shares of IPL System Inc., an affiliate under common control. At December 31, 2013, the investment of $825 million (2012 - $825 million) in these shares resulted in a weighted average dividend yield of 7.6%.

At December 31, 2013, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.5%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preference shares of the Company. For the year ended December 31, 2013, interest paid amounted to $27 million (2012 - $34 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 0.55% and is payable on demand.

Treasury and Other Management Services
Enbridge provides treasury and other management services and charges the Company on a cost recovery basis.

Natural Gas Purchases
The Company has contracted for the purchase of natural gas from Tidal Energy Marketing Inc. and Tidal Energy Marketing (U.S.) LLC, related entities under common control, at prevailing market prices and under normal trade terms. Contractual obligations under these contracts are 2014 - $52 million and nil thereafter.

Wholesale Service
These gas procurement and transportation services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Transportation Services
The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2014 - $74 million, 2015 to 2016 - $82 million, 2017 to 2018 - $16 million and thereafter - nil.

Trade Receivables and Payables
The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is charged. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

Other Transactions
In 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund, an affiliated entity under common control, for cash proceeds of $72 million *(Note 6)*.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

22. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $3,010 million which are expected to be paid within the next five years and $649 million in total for years thereafter.

Minimum future payments under operating leases are estimated at $12 million in aggregate. Estimated annual lease payments for the years ended December 31, 2014 through 2018 are $4 million, $4 million, $3 million, $1 million and nil, respectively. Total rental expense for operating leases, classified in Operating and administrative expense, was $3 million for each of the years ended December 31, 2013, 2012 and 2011.

CONTINGENCIES

Former Manufactured Coal Gas Plant Sites
The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2013 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

OTHER LITIGATON

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

CORPORATE INFORMATION

TRUSTEE AND REGISTRARS

Debenture
9.85% debenture

CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6
and in Montreal and Vancouver

For the above debenture, CIBC Mellon Trust Company of Canada is the Interest Dispersing Agent.

REGISTRAR AND PAYING AGENT

Medium Term Notes
Canadian Imperial Bank of Commerce
Debt Management Service
22 Front Street West, 5th Floor
Toronto, Ontario, M5J 2W5

TRUSTEE

Medium Term Notes
CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6

REGISTRAR AND TRANSFER AGENT

Group 3 Preference Shares
Computershare Investor Services Inc.
100 University Avenue, 8th Floor
Toronto, Ontario, M5J 2Y1

CORPORATE GOVERNANCE

The size of the Board of Directors of the Company is currently set at six (6) members, two (2) of whom are considered to be independent directors.

The Board has an Audit, Finance & Risk Committee comprised of the following directors:

J. L. Braithwaite
D. A. Leslie
J. R. Bird

The Audit, Finance & Risk Committee's key responsibilities include the review of the consolidated financial statements, and systems of internal financial and compliance control.

The governance of the Company is the responsibility of the Board of Directors and the Audit, Finance & Risk Committee of the Board, who are also responsible under law for the supervision of the management of the Company's businesses and affairs and have the statutory authority and obligation to act honestly and in good faith with a view to the best interests of the Company.

The Board makes independent decisions and also receives recommendations from the following committees of the Enbridge Inc. Board of Directors, who act in an advisory capacity to the Board of Directors of the Company:

- Governance Committee
- Human Resources & Compensation Committee
- Corporate Social Responsibility Committee

In addition to the committee structure and mandate of the Board of Directors outlined above, the Board of Directors has adopted and governs itself in accordance with Enbridge Inc.'s corporate governance practices as expressed in the *Corporate Governance Practices* of Enbridge annually disclosed in its *Management Information Circular* (last dated March 5, 2013), which is incorporated herein by reference.

ENBRIDGE GAS DISTRIBUTION INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2014

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Gas Distribution Inc.

Financial Reporting
Management of Enbridge Gas Distribution Inc. (the Company) is responsible for the accompanying consolidated financial statements and all related financial information, including Management's Discussion and Analysis (MD&A). The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, includes directors who are unrelated and independent, and has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with U.S. GAAP and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

(Signed)

Glenn W. Beaumont
President

(Signed)

William M. Ramos
Vice President, Finance & Regulatory

February 18, 2015

February 18, 2015

Independent Auditor's Report

To the Shareholders of
Enbridge Gas Distribution Inc.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2014 and December 31, 2013 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2014, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215, www.pwc.com/ca

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and its subsidiaries as at December 31, 2014 and December 31, 2013 and its results of operations and its cash flows for each of the three years in the period ended December 31, 2014 in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Gas commodity and distribution revenue *(Note 20)*	**2,803**	2,221	1,869
Transportation of gas for customers	**305**	328	345
	3,108	2,549	2,214
Gas commodity and distribution costs, excluding depreciation *(Note 20)*	**(2,046)**	(1,480)	(1,229)
	1,062	1,069	985
Other revenue *(Note 4)*	**92**	97	202
	1,154	1,166	1,187
Expenses			
Operating and administrative *(Note 20)*	**493**	496	489
Depreciation and amortization *(Notes 3, 7 and 9)*	**286**	304	320
Earnings sharing *(Note 4)*	**12**	-	10
	791	800	819
	363	366	368
Other income	**66**	65	63
Interest expense, net *(Notes 11, 16 and 20)*	**(177)**	(171)	(170)
	252	260	261
Income taxes *(Note 17)*	**(6)**	(43)	(53)
Earnings from continuing operations	**246**	217	208
Discontinued operations *(Note 5)*			
Earnings from discontinued operations before income taxes	**-**	-	6
Income taxes from discontinued operations	**-**	-	(2)
Earnings from discontinued operations	**-**	-	4
Earnings	**246**	217	212
Preference share dividends *(Note 13)*	**(2)**	(2)	(2)
Earnings attributable to the common shareholder	**244**	215	210

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings	**246**	217	212
Other comprehensive income/(loss), net of tax *(Notes 15 and 16)*			
Change in unrealized gain/(loss) on cash flow hedges	**(62)**	81	(1)
Reclassification to earnings of realized loss on cash flow hedges	**-**	1	2
Reclassification to earnings of unrealized gain on cash flow hedges	**-**	(2)	-
Actuarial gain/(loss) on other postretirement benefits *(Note 18)*	**(7)**	10	(3)
Change in foreign currency translation adjustment	**3**	1	-
Other comprehensive income/(loss)	**(66)**	91	(2)
Comprehensive income	**180**	308	210
Preference share dividends	**(2)**	(2)	(2)
Comprehensive income attributable to the common shareholder	**178**	306	208

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Preference shares *(Note 13)*	**100**	100	100
Common shares *(Note 13)*			
Balance at beginning of year	**1,287**	1,137	1,137
Common shares issued	**150**	150	-
Balance at end of year	**1,437**	1,287	1,137
Additional paid-in capital			
Balance at beginning of year	**1,148**	1,148	1,131
Disposition *(Note 5)*	**-**	-	17
Balance at end of year	**1,148**	1,148	1,148
Retained earnings/(deficit)			
Balance at beginning of year	**22**	7	(2)
Earnings attributable to the common shareholder	**244**	215	210
Common share dividends declared	**(204)**	(200)	(201)
Balance at end of year	**62**	22	7
Accumulated other comprehensive income/(loss) *(Note 15)*			
Balance at beginning of year	**65**	(26)	(24)
Other comprehensive income/(loss)	**(66)**	91	(2)
Balance at end of year	**(1)**	65	(26)
Total shareholders' equity	**2,746**	2,622	2,366

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Operating activities			
Earnings	**246**	217	212
Earnings from discontinued operations	**-**	-	(4)
Depreciation and amortization	**286**	304	320
Deferred income taxes	**4**	(9)	20
Refund of revenues *(Note 4)*	**52**	-	-
Recognition of regulatory asset *(Note 4)*	**-**	-	(89)
Other	**13**	12	13
Premium/(discount) on issuance of term notes	**(1)**	12	-
Changes in operating assets and liabilities *(Note 19)*	**(1,014)**	(86)	71
Cash provided by/(used) continuing operations	**(414)**	450	543
Cash provided by discontinued operations *(Note 5)*	**-**	-	12
	(414)	450	555
Investing activities			
Additions to property, plant and equipment	**(601)**	(519)	(414)
Additions to intangible assets	**(36)**	(34)	(38)
Change in construction payable	**11**	6	(11)
Proceeds on sale of assets *(Note 5)*	**-**	-	72
	(626)	(547)	(391)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**569**	(210)	33
Net change in short-term note payable to affiliate company *(Note 20)*	**189**	2	5
Term note issues	**730**	400	-
Term note repayments	**(400)**	-	-
Common shares issued *(Note 13)*	**150**	150	-
Preference share dividends	**(2)**	(2)	(2)
Common share dividends	**(203)**	(200)	(206)
Other	**(2)**	(2)	-
	1,031	138	(170)
Increase/(decrease) in cash and cash equivalents	**(9)**	41	(6)
Cash and cash equivalents at beginning of year	**44**	3	9
Cash and cash equivalents at end of year	**35**	44	3
Cash and cash equivalents – discontinued operations *(Note 5)*	**-**	-	-
Cash and cash equivalents – continuing operations	**35**	44	3
Supplementary cash flow information			
Income taxes paid	**23**	42	31
Interest paid *(Note 11)*	**191**	169	176

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2014**	2013
(millions of Canadian dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**35**	44
Accounts receivable and other *(Notes 4, 6, 16, 17 and 20)*	**1,189**	706
Gas inventories *(Note 2)*	**563**	382
	1,787	1,132
Property, plant and equipment, net *(Note 7)*	**6,268**	5,869
Investment in affiliate company *(Notes 16 and 20)*	**825**	825
Deferred amounts and other assets *(Notes 4, 8, 16 and 17)*	**738**	379
Intangible assets, net *(Note 9)*	**161**	174
	9,779	8,379
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**9**	4
Short-term borrowings *(Note 11)*	**938**	374
Short-term borrowings from affiliate *(Notes 11 and 20)*	**204**	15
Accounts payable and other *(Notes 4, 10, 16 and 20)*	**974**	769
Current maturities of long-term debt *(Note 11)*	**2**	400
	2,127	1,562
Long-term debt *(Note 11)*	**3,125**	2,399
Other long-term liabilities *(Notes 4, 12 and 16)*	**943**	1,026
Deferred income taxes *(Note 17)*	**463**	395
Loans from affiliate company *(Notes 11 and 20)*	**375**	375
	7,033	5,757
Commitments and contingencies *(Notes 20 and 21)*		
Shareholders' equity		
Share capital *(Note 13)*		
Preference shares *(convertible; 4 outstanding at December 31, 2014 and 2013)*	**100**	100
Common shares *(159 and 151 outstanding at December 31, 2014 and 2013, respectively)*	**1,437**	1,287
Additional paid-in capital	**1,148**	1,148
Retained earnings	**62**	22
Accumulated other comprehensive income/(loss) *(Note 15)*	**(1)**	65
	2,746	2,622
	9,779	8,379

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

(Signed)

Glenn W. Beaumont
President

(Signed)

J. Herb England
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

The Company also owns and operates regulated and unregulated natural gas storage facilities in Ontario. Between August 2011 and December 2012, the Company owned and operated two unregulated solar projects located in Amherstburg, Ontario, through a 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. The Company is permitted to prepare its consolidated financial statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under an exemption granted by securities regulators in Canada until 2018.

BASIS OF PRESENTATION AND USE OF ESTIMATES
The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 4)*; unbilled revenues *(Note 6)*; allowance for doubtful accounts *(Note 6)*; depreciation rates and carrying value of property, plant and equipment *(Notes 2 and 7)*; amortization rates and carrying value of intangible assets *(Note 9)*; valuation of stock-based compensation *(Note 14)*; fair value of financial instruments *(Note 16)*; provisions for income taxes *(Note 17)*; assumptions used to measure retirement and other postretirement benefit obligations (OPEB) *(Note 18);* commitments and contingencies *(Note 21)*; and fair value of asset retirement obligations (ARO). Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION
The consolidated financial statements include the accounts of the Company and its subsidiaries. All significant intercompany accounts and transactions are eliminated upon consolidation.

REGULATION
The utility operations of the Company, excluding St. Lawrence, are regulated by the Ontario Energy Board (OEB) and the utility operations of St. Lawrence are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities *(Note 4)*.

REVENUE RECOGNITION

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise area.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

PUSH-DOWN ACCOUNTING

The Company elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by the Company. Upon adopting push-down accounting, the historical cost of the Company's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges at December 31, 2014 or 2013.

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/loss (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

The Company recognizes the fair value of derivative instruments on the Consolidated Statements of Financial Position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with Deferred amounts and other assets. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

INCOME TAXES

The liability method of accounting for income taxes is followed. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as approved by the Regulators for rate-making purposes. As a result, rates do not include the recovery of deferred income taxes related to temporary differences. A corresponding deferred income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates (*Note 4*).

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Consolidated Statement of Financial Position. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. The effects of translating the financial statements of St. Lawrence to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI). Asset and liability accounts are translated at the exchange rates in effect on the date of the Consolidated Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

The Company extinguishes liabilities when a creditor has relieved the Company of its obligation, which occurs when the Company's financial institution honours a cheque that the creditor has presented for payment. Accordingly, obligations for which the Company has issued cheque payments that have not been presented to the financial institution totaling \$23 million as of December 31, 2014 (2013 - \$9 million) are included in Accounts payable and other on the Consolidated Statements of Financial Position.

GAS INVENTORIES

Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators.

Included in, or deducted from, physical gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2014, $33 million (2013 - $28 million) of natural gas was held on behalf of transportation service customers. These transactions have no impact on the Company's consolidated earnings or financial position.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates authorized by the Regulators. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit.

The Regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily include: costs which the Regulators have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; derivative financial instruments; and deferred financing costs.

INTANGIBLE ASSETS

Intangible assets consist primarily of the Company's Customer Information System (CIS) and software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS

ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. In 2014, new mortality assumptions were adopted by the Company for the measurement of the December 31, 2014 benefit obligations. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. During the year ended December 31, 2012, the Company refined the methodology by which it determines discount rates, in particular, refining the method by which it estimates spreads for bonds with longer term maturities. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contributions occur.

The Company also provides OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities, respectively, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

The Company expects to recover pension expense in future rates and therefore records a corresponding regulatory asset to the extent such recovery is deemed to be probable. For years prior to 2012, a regulatory asset related to OPEB obligation was not recorded as a rate order allowing for the recovery of these costs in rates had not yet been obtained. Commencing in 2012, pursuant to a specific rate order allowing for recovery in rates of OPEB costs determined on an accrual basis, a corresponding regulatory asset was recognized. In the absence of rate regulation, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION

Enbridge grants stock-based compensation to certain employees and senior officers of the Company through four long-term incentive compensation plans. Compensation expense associated with each of the plans, as determined under the methods outlined below is recognized in Operating and administrative expense. Amounts owing to Enbridge in respect of stock-based compensation are payable on a quarterly basis.

Incentive Stock Options (ISOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISOs granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility.

Performance Stock Units (PSUs) and Restricted Stock Units (RSUs) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of the Company's shares. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

ADOPTION OF NEW STANDARDS

Obligations Resulting from Joint and Several Liability Arrangements

Effective January 1, 2014, the Company retrospectively adopted Accounting Standards Update (ASU) 2013-04 which provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Extraordinary and Unusual Items

ASU 2015-01 was issued in January 2015 and eliminates the concept of extraordinary items from GAAP. Entities will no longer be required to separately classify and present extraordinary events in the income statement, net of tax, after income from continuing operations. This accounting update is effective for annual and interim reporting periods beginning after December 15, 2015 and may be applied prospectively or retrospectively. The adoption of the pronouncement is not anticipated to have an impact on the consolidated financial statements.

Revenue from Contracts with Customers

ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. The new standard is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

ASU 2014-8 was issued in April 2014 and changes the criteria and disclosures for reporting discontinued operations. It is anticipated that in general, the revised criteria will result in fewer transactions being categorized as discontinued operations. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively. The adoption of the pronouncement is not anticipated to have an impact on the Company’s consolidated financial statements.

CHANGES IN ACCOUNTING ESTIMATES

Depreciation Rates

In 2014, the Company revised depreciation rates based on the results of a new net negative salvage study which was approved by the Ontario Energy Board (OEB) as part of the 2014 to 2018 customized incentive regulation (IR) plan. The revised rates decreased depreciation and amortization expense by $44 million for the year ended December 31, 2014.

4. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

For the purposes of this note, “Enbridge Gas Distribution” refers specifically to Enbridge Gas Distribution Inc. excluding St. Lawrence, whereas “St. Lawrence” refers specifically to St. Lawrence Gas Company, Inc.

RATE APPROVAL

The OEB issued a decision in July 2014, with a subsequent decision and rate order in August 2014 on the Company's customized IR application for the setting of rates for the period of 2014 through 2018. The customized IR plan requires allowed revenue, and consequently rates, to be updated for select items. The OEB also approved the adoption of a new approach for determining net negative salvage percentages to be included within the Company's depreciation rates. Under the customized IR plan, the Company shares equally with customers, earnings above the approved base return.

Under the customized IR plan, the Company will continue to apply the accounting guidance found in Accounting Standards Codification (ASC) 980 – Regulated Operations.

For the year ended December 31, 2013, Enbridge Gas Distribution's rates were set pursuant to an OEB approved settlement agreement and decision related to its 2013 cost of service (COS) rate application. For the years ended December 31, 2014, 2013 and 2012, St. Lawrence's rates were set using a COS methodology. Under COS, revenues are set to recover costs and to earn a rate of return on the deemed common equity component of rate base. Costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, interest and income taxes. Rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under 2014 and 2013 COS, St. Lawrence's revenues were set to earn a rate of return on the deemed common equity component of rate base. Gas costs are not recovered through revenue rates, but are set separately in gas cost rates. Under COS, it is the responsibility of Enbridge Gas Distribution and St. Lawrence to demonstrate to the Regulators the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken.

For the year ended December 31, 2012, Enbridge Gas Distribution's rates were set using its OEB approved revenue per customer cap IR methodology, which was in place from 2008 through 2012. The IR methodology adjusted revenues, and consequently rates, annually and relied on an annual process to forecast volume and customer additions. Under the IR mechanism, Enbridge Gas Distribution was allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps was required to be shared with customers on an equal basis.

During the years ended December 31, 2014, 2013 and 2012, the cost of natural gas is passed on to customers as a flow-through.

APPROVED RATES

Enbridge Gas Distribution

Enbridge Gas Distribution's rates for 2014 included an after-tax rate of return on common equity of 9.36% (2013 - 8.93% and 2012 - 8.39%) based on a 36% (2013 and 2012 - 36%) deemed common equity component of rate base.

St. Lawrence

St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 10.5% for the year ended December 31, 2014 (2013 and 2012 - 10.5%) based on a 50% (2013 and 2012 - 50%) deemed common equity component of rate base. Any earnings above a return on equity of 11% (2013 and 2012 - 11%) were shared equally with customers. The calculation of such earnings was cumulative from January 1, 2010 to December 31, 2014 and resulted in no sharing impact as at December 31, 2014 (2013 and 2012 - nil).

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities

As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. The Regulators' future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

FINANCIAL STATEMENT EFFECTS

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	**2014**	2013	Consolidated Statement of Financial Position Location**	Estimated Recovery/ Settlement Period *(years)*
(millions of Canadian dollars)				
Regulatory assets/(liabilities)				
Enbridge Gas Distribution				
Purchased gas variance[1]	**673**	(6)	AR/DA	*
Deferred income taxes[2]	**270**	209	AP/DA	*
Pension plans, net[3]	**90**	2	DA/OLTL	*
OPEB[4]	**84**	89	AR/DA	18
Constant dollar net salvage adjustment[5]	**37**	-	DA	*
Unabsorbed demand cost[6]	**14**	-	AR	*
Design day criteria transportation[7]	**13**	-	AR	*
Demand side management incentive[8]	**13**	16	AR	*
Unaccounted for gas variance[9]	**13**	8	AR	1
Customer care CIS rate smoothing deferral[10]	**8**	5	DA	4
Deferred rate hearing costs[11]	**2**	4	AR	2
Average use true-up variance[12]	**1**	10	AR/AP	*
Future removal and site restoration reserves[13]	**(536)**	(905)	OLTL	*
Site restoration clearance adjustment[14]	**(283)**	-	AP/OLTL	4
Revenue adjustment[15]	**(52)**	-	AP	1
Transactional services deferral[16]	**(26)**	(51)	AP	1
Earnings sharing deferral[17]	**(12)**	(7)	AP	*
Storage and transportation deferral[18]	**(3)**	(3)	AP	1
Post-retirement true-up variance[19]	**(3)**	3	AR/AP/OLTL	*
Other regulatory assets and liabilities	**(3)**	1	***	***
	300	(625)		
St. Lawrence				
Other regulatory assets and liabilities	**5**	(1)	***	***
	5	(1)		
	305	(626)		

* Refer to the footnote for details

** AR – Accounts receivable and other
AP – Accounts payable and other
DA – Deferred amounts and other assets
OLTL – Other long-term liabilities

*** Dependent on the nature of the item

1 *Purchased gas variance (PGVA) is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. In the*

absence of rate regulation, the actual cost of natural gas would be included in gas commodity and distribution costs, excluding depreciation and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established.

2 *The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

3 *The pension plan balance represents the regulatory offset to the pension liability/asset to the extent the amounts are to be collected/refunded in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

4 *The OPEB balance represents the Company's right to recover OPEB costs pursuant to an OEB rate order, which allows the amount to be collected in rates over a 20-year period commencing in 2013. In the absence of rate regulation, this regulatory balance and related earnings impact would not be recorded.*

5 *The Constant dollar net salvage adjustment represents the cumulative variance between the amount proposed for clearance and the actual amount cleared, relating specifically to the site restoration clearance adjustment. At the end of 2018 any residual balance will be cleared in a post 2018 true up, ensuring that the actual amount cleared is equivalent to the required $380 million.*

6 *The Unabsorbed demand cost deferral account (UDCDA) represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet increased requirements resulting from the Peak Gas Design Day Criteria (PGDDC). Enbridge Gas Distribution updated its PGDDC in 2013 and 2014. The impact of this update was phased in equally over the two years. The balance for 2014 captures the cost consequences of unutilized transportation capacity above the amount associated with the 2014 Design day criteria transportation deferral account (DDCTDA). In the absence of rate regulation, these costs would be expensed as incurred.*

7 *DDCTDA balance represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet increased requirements resulting from the PGDDC. Enbridge Gas Distribution updated its PGDDC in 2013 and 2014. The impact of this update was phased in equally over the two years. The heating degree days used within its design day criteria for 2013 and 2014's design day criteria were updated. The balance for 2014 captures the cost consequences of unutilized transportation capacity associated with the 2014 DDCTDA. In the absence of rate regulation, these costs would be expensed as incurred.*

8 *Demand side management incentive deferral account (DSMIDA), previously referred to as shared savings mechanism deferral account, represents the benefit derived by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the DSMIDA amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation.*

9 *Unaccounted for gas variance represents the difference between the total natural gas distributed by Enbridge Gas Distribution and the amount of natural gas billed or billable to customers for their recorded consumption, to the extent it is different from the approved amount built into rates. Enbridge Gas Distribution has deferred unaccounted for gas variance and has historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation, this variance would be included in earnings in the year incurred.*

10 *Customer care CIS rate smoothing deferral represents the difference between the forecast costs and the approved costs for customer care and CIS reflected in rates. The balance will accumulate during 2013 to 2015 when the cost per customer exceeds the cost approved for recovery in rates. The balance will be drawn down during 2016 to 2018 when the cost per customer is lower than the cost approved for recovery in rates. Enbridge Gas Distribution has received OEB approval to collect from or refund to customers any remaining balance after 2018. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

11 *Deferred rate hearing costs variance account (OHCVA) is rate hearing costs incurred by Enbridge Gas Distribution for the regulatory process. Historically, Enbridge Gas Distribution had been granted OEB approval for recovery of such hearing costs, generally within two years. Beginning in 2014, the OHCVA has been discontinued. In the absence of rate regulation, these costs would be expensed as incurred.*

12 *Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual weather normalized average use for general service customers. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

13 *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

14 *The Site restoration clearance adjustment represents the amount, that was determined by the OEB, of previously collected costs for future removal and site restoration that is now considered to be in excess of future requirements and will be refunded to customers over the customized IR term. This was a result of the OEB's approval of the adoption of a new approach for determining net negative salvage percentages. The new approach resulted in lower depreciation rates and lower future removal and site restoration reserves. There would be no change in the treatment of this item in the absence of rate regulation.*

15 *The revenue adjustment represents the revenue variance between interim rates, which were in place from January 2014 to September 2014, and the final OEB approved 2014 rates, which were implemented in October 2014, but effective in January 2014. The revenue adjustment balance is the 2014 OEB approved revenue adjustment amount to be refunded to customers in January 2015. There would be no change in the treatment of this item in the absence of rate regulation.*

16 *Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.*

17 *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the customized IR plan applicable to 2014. The earnings sharing is payable to customers and represented 50% of normalized 2014 U.S. GAAP earnings represented by the ROE in excess of the allowed utility return on equity threshold applicable to Enbridge Gas Distribution under the customized IR. The December 31, 2014 balance related to the year ended December 31, 2014. Earnings sharing did not apply to the 2013 COS Settlement. There would be no change in the treatment of this item in the absence of rate regulation.*

18 *Storage and transportation deferral represents the difference between the actual cost and the approved cost of natural gas storage and transportation reflected in rates. Enbridge Gas Distribution has historically been granted OEB approval to collect this balance from or to refund this balance to customers, generally in the subsequent year. In the absence of rate regulation, the actual cost of natural gas storage and transportation would be included in gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount, as the right to collect or refund the revenue or costs has been established.*

19 *Post-retirement true-up variance is the difference between the actual cost and the approved cost of pension and OPEB reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers in the subsequent year, up to a maximum of $5 million per year. Any amounts in excess of $5 million per year will be deferred for refund or collection in the next subsequent year. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Revenue
To recognize the actions or expected actions of the Regulators, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

In 2012, the Company received a rate order from the OEB permitting recovery of OPEB costs in the amount of $89 million. The rate order allows this amount to be collected in rates over a 20-year period commencing in 2013, and was presented in Other revenue for the year ended December 31, 2012. In the absence of rate regulation, this earnings impact would not have been recorded.

Operating Cost Capitalization
With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2014, cumulative costs relating to this services contract of $166 million (2013 - $154 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment
In the absence of rate regulation, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred. Further, on the retirement of utility assets, the excess of the book value net of proceeds would be recorded as a loss on the sale of assets in earnings in the period of retirement. Any removal costs incurred would be booked against the future removal and site restoration balance (described above).

Intangible Assets
The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2014, the net book value of these costs was $60 million (2013 - $73 million). In the absence of rate regulation, a portion of the original cost of these assets would have been expensed in the period incurred.

Gas Inventories
Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. Included in gas inventories at December 31, 2014 is $42 million (2013 - $40 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation, these costs would be expensed as incurred and inventory would be recorded at the lower of cost or market value.

Depreciation
In the absence of rate regulation, depreciation rates would not have included a charge for future removal and site restoration costs.

5. DISCONTINUED OPERATIONS

In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to Enbridge Income Fund (the Fund), an affiliated entity under common control, for proceeds of $72 million. Project Amherstburg consisted primarily of property, plant and equipment and intangible assets. The excess of the sale price over the net book value at the time of disposition of $17 million inclusive of deferred income tax recoveries of $10 million were recognized as Additional paid-in capital. No gain or loss was recognized in earnings on the disposition; however $5 million of cash income taxes incurred on the related capital gain remains as a charge to consolidated earnings for the year ended December 31, 2012.

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2014**	2013
(millions of Canadian dollars)		
Regulatory assets *(Note 4)*	**567**	54
Trade receivables	**372**	357
Unbilled revenues	**161**	211
Taxes receivable	**28**	9
Current deferred income taxes *(Note 17)*	**23**	2
Due from affiliates *(Note 20)*	**11**	13
Prepaid expenses	**8**	7
Short-term portion of derivative assets *(Note 16)*	**-**	36
Agent billing and collection receivable	**-**	15
Other	**52**	33
Allowance for doubtful accounts *(Note 16)*	**(33)**	(31)
	1,189	706

During the first quarter of 2014, increases in natural gas prices and colder than normal weather resulted in the Company accumulating a significant balance in its PGVA. Included in Accounts receivable and other at December 31, 2014 is $491 million (December 31, 2013 - $6 million in Accounts payable and other) which represents the PGVA balance that is expected to be recovered from customers within the next 12 months.

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2014**	2013
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	**2.2%**	**3,593**	3,342
Gas services	**2.3%**	**2,798**	2,667
Regulating and metering equipment	**5.8%**	**825**	781
Gas storage	**2.2%**	**323**	314
Right-of-way	**1.2%**	**52**	48
Computer technology	**36.1%**	**40**	36
Under construction	**-**	**307**	198
Construction materials inventory	**-**	**39**	35
Land	**-**	**24**	23
Other	**6.9%**	**289**	280
		8,290	7,724
Accumulated depreciation		**(2,115)**	(1,949)
		6,175	5,775
Unregulated property, plant and equipment			
Gas storage	**2.2%**	**88**	87
Other	**8.1%**	**27**	24
		115	111
Accumulated depreciation		**(22)**	(17)
		93	94
Property, plant and equipment, net		**6,268**	5,869

Depreciation expense, including amounts collected for future removal and site restoration costs, was $237 million for the year ended December 31, 2014 (2013 - $267 million, 2012 - $289 million). Additional information about the impact of the revised depreciation rates is included in Note 3.

8. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2014**	2013
(millions of Canadian dollars)		
Regulatory assets *(Note 4)*	**711**	312
Deferred financing costs	**12**	11
Deferred income taxes *(Note 17)*	**8**	1
Pension and OPEB asset *(Note 18)*	**4**	8
Long-term portion of derivative assets *(Note 16)*	**-**	46
Other	**3**	1
	738	379

At December 31, 2014, deferred amounts of $34 million (2013 - $31 million) were subject to amortization and are presented net of accumulated amortization of $22 million (2013 - $20 million). Amortization expense for the year ended December 31, 2014 was $2 million (2013 and 2012 - $2 million).

In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. Included in Deferred amounts and other assets at December 31, 2014 is $182 million (2013 - nil) which represents the portion of the PGVA balance that is expected to be recovered beyond the next 12 months.

9. INTANGIBLE ASSETS

December 31, 2014	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**24.1%**	**198**	**(97)**	**101**
CIS	**10.0%**	**127**	**(67)**	**60**
		325	**(164)**	**161**

December 31, 2013	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	22.8%	162	(61)	101
CIS	10.0%	127	(54)	73
		289	(115)	174

Intangible assets include $23 million of work-in-progress as at December 31, 2014 (2013 - $19 million). Total amortization expense for intangible assets was $49 million for the year ended December 31, 2014 (2013 - $37 million, 2012 - $31 million). The Company expects aggregate amortization expense for the years ending December 31, 2015 through 2019 of $43 million, $49 million, $47 million, $45 million and $41 million, respectively.

10. ACCOUNTS PAYABLE AND OTHER

December 31,	**2014**	2013
(millions of Canadian dollars)		
Operating accrued liabilities	**365**	329
Regulatory liabilities *(Note 4)*	**233**	76
Budget billing plan payable	**137**	82
Security deposits	**61**	62
Dividends payable	**52**	51
Due to affiliates *(Note 20)*	**44**	55
Trade payables	**27**	40
Interest payable	**27**	28
Taxes payable	**11**	22
Short-term portion of derivative liabilities *(Note 16)*	**6**	-
Current portion of OPEB liability *(Note 18)*	**4**	4
Agent billing and collection payable	**2**	-
Other	**5**	20
	974	769

Included in Accounts payable and other at December 31, 2014 is $52 million (2013 - nil) relating to the 2014 OEB approved revenue adjustment that will be refunded to customers as a result of the variance between interim rates and final OEB approved 2014 rates. Also included in Accounts payable and other at December 31, 2014 is $90 million (2013 - nil) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers within the next 12 months.

11. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2014**	2013
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	85
Medium-term notes	4.73%	2017-2050	**3,025**	2,695
Commercial paper and credit facility draws, net[1]			**1,122**	382
Other[2]			**37**	26
Total debt			**4,269**	3,188
Current maturities			**(2)**	(400)
Short-term borrowings	1.32%		**(938)**	(374)
Short-term borrowings from affiliates *(Note 20)*	2.18%		**(204)**	(15)
Long-term debt			**3,125**	2,399
Loans from affiliate company *(Note 20)*			**375**	375

1 *Includes amounts drawn on uncommitted demand credit facilities.*
2 *Consists of note payable to affiliate company and debt premium.*

In April 2014, the Company issued $300 million of three-year medium-term notes at an interest rate of 1.85%. In June 2014, a new $1,000 million shelf prospectus was filed as a continuation of the Company's medium-term note program, which was last renewed in January 2013. The prospectus is effective for a 25-month period.

In August 2014, the Company issued $215 million of ten-year medium-term notes at an interest rate of 3.15% and $215 million of thirty-year medium-term notes at an interest rate of 4.00%.

For the years ending December 31, 2015 through 2019, medium-term note maturities are $2 million, $2 million, $502 million, $1 million and $1 million, respectively. The Company's debentures and medium-term notes bear interest at fixed rates, and interest obligations for the years ending December 31, 2015 through 2019 are $151 million, $151 million, $149 million, $135 million and $136 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Debentures and medium-term notes	**149**	138	139
Loans from affiliate company *(Note 20)*	**29**	27	27
Commercial paper and credit facility draws	**9**	4	2
Other interest and finance costs	**(4)**	9	8
Capitalized	**(6)**	(7)	(6)
	177	171	170

In 2014, total interest paid to third parties was $163 million (2013 and 2012 - $142 million) and total interest paid to affiliate company was $29 million (2013 - $27 million, 2012 - $34 million).

CREDIT FACILITIES

The Company currently has a $1,000 million commercial paper program limit that is backstopped by committed lines of credit of $1,000 million. The term of any commercial paper issued under this program may not exceed one year. The maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option.

In June 2014, the Company obtained a new $300 million revolving credit facility from Enbridge Inc. which has a term out date in June 2015 and a maturity date in June 2016. As at December 31, 2014, $175 million was drawn on this credit facility. The Company also increased its external credit facility by $300 million to a total of $1,000 million and extended the term out date for an additional year to July 2015, with a maturity date in July 2016.

		December 31, 2014			December 31, 2013
	Maturity Dates	Total Facilities[1]	Draws[2]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge Gas Distribution Inc.	2016	**1,300**	**1,110**	**190**	700
St. Lawrence Gas Company, Inc.	2019	**8**	**8**	**-**	13
Total credit facilities		**1,308**	**1,118**	**190**	713

1 Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the credit facility.
2 Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the external credit facility.

In addition to the committed credit facilities noted above, St. Lawrence Gas Company, Inc. also has $6 million (2013 - $5 million) of uncommitted demand credit facilities, of which $2 million (2013 - $1 million) was unutilized as at December 31, 2014.

Credit facilities carried a weighted average standby fee of 0.2% on the unused portion and draws bear interest at market rates.

The Company's borrowings, whether debentures or medium-term notes, are unsecured. When issuing any new indebtedness with a maturity over 18 months, covenants contained in the Company's trust indenture require the pro forma long-term debt interest coverage ratio to be at least 2.0 times for 12 consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as U.S. GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of financing costs and intercompany interest expense less gains on asset dispositions divided by the annual interest requirement. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. As at December 31, 2014, the Company was in compliance with this covenant.

12. OTHER LONG-TERM LIABILITIES

December 31,	2014	2013
(millions of Canadian dollars)		
Regulatory liabilities *(Note 4)*	**740**	916
Pension and OPEB liabilities *(Note 18)*	**190**	104
Long-term portion of derivative liabilities *(Note 16)*	**5**	-
Other	**8**	6
	943	1,026

13. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preference shares.

COMMON SHARES

	2014		2013		2012	
December 31,	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**150.6**	**1,287**	142.3	1,137	142.3	1,137
Common shares issued	**8.3**	**150**	8.3	150	-	-
Balance at end of year	**158.9**	**1,437**	150.6	1,287	142.3	1,137

PREFERENCE SHARES

December 31, 2014, 2013, and 2012	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preference shares in millions)			
Group 1	0.2	-	-
Group 2, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 2, Series D, Cumulative Redeemable Convertible	4	-	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	-	-
Group 5	10	-	-
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preference shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case. As at December 31, 2014, no preference shares have been redeemed.

On July 1, 2019, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference shares on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period. The Group 3, Series D preference shareholders opted not to convert their shares into Group 2, Series D preference shares effective July 1, 2014.

The Group 2, Series D preference shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder's option on July 1, 2019 and every five years thereafter.

14. STOCK OPTION AND STOCK UNIT PLANS

Enbridge's four long-term incentive compensation plans include the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. The Company reimburses Enbridge for stock-based compensation costs associated with its employees on a quarterly basis. As of December 31, 2014, the Company did not have any employees that had options in the PBSO Plan.

INCENTIVE STOCK OPTIONS

Key employees of the Company are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2014	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**2,490**	**28.81**		
Options granted	**468**	**48.81**		
Options exercised[1]	**(363)**	**20.19**		
Options cancelled	**(7)**	**31.87**		
Employee movements from other Enbridge companies	**77**	**30.07**		
Options outstanding at end of year	**2,665**	**33.53**	**6.3**	**48**
Options vested at end of year[2]	**1,529**	**26.02**	**4.8**	**39**

1 The total intrinsic value of ISOs exercised during the year ended December 31, 2014 was $11 million (2013 - $7 million; 2012 - $11 million) and cash received by Enbridge on exercise was $5 million (2013 - $2 million; 2012 - $6 million).

2 The total fair value of options vested under the ISO Plan during the year ended December 31, 2014 was $2 million (2013 and 2012 - $2 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2014**	2013	2012
Fair value per option *(Canadian dollars)*[1]	**5.53**	5.27	4.81
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	5
Expected volatility[3]	**16.9%**	17.4%	19.7%
Expected dividend yield[4]	**2.9%**	2.8%	3.0%
Risk-free interest rate[5]	**1.6%**	1.2%	1.3%

1 Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $5.45 (2013 - $5.15; 2012 - $4.65) for Canadian employees and US$5.35 (2013 - US$5.63, 2012 - US$5.58) for United States employees.

2 The expected option term is based on historical exercise practice.

3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.

4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.

5 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.

Compensation expense recorded for the year ended December 31, 2014 for ISOs was $4 million (2013 and 2012 - $3 million). At December 31, 2014, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $4 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan for senior officers of the Company where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two if Enbridge performs within the highest range of its performance targets. The 2012, 2013 and 2014 grants derive the performance multiplier through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's earnings per share, adjusted for unusual non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2014 expense, multipliers of two, based upon multiplier estimates at December 31, 2014, were used for each of the 2012, 2013 and 2014 PSU grants.

December 31, 2014	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**19**		
Units granted	**15**		
Units matured[1]	**(9)**		
Dividend reinvestment	**1**		
Units outstanding at end of year	**26**	**1.6**	**3**

1 *The total amount paid by Enbridge during the year ended December 31, 2014 for PSUs was $1 million (2013 - $2 million; 2012 - $1 million).*

Compensation expense recorded for the year ended December 31, 2014 for PSUs was $5 million (2013 - $4 million; 2012 - $7 million). As of December 31, 2014, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $2 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a RSU Plan where cash awards are paid to certain non-executive employees of the Company following a 35-month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2014	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**203**		
Units granted	**96**		
Units cancelled	**(9)**		
Units matured[1]	**(105)**		
Dividend reinvestment	**8**		
Employee movements from other Enbridge companies	**3**		
Units outstanding at end of year	**196**	**1.4**	**10**

1 *The total amount paid by Enbridge during the year ended December 31, 2014 for RSUs was $5 million (2013 - $5 million; 2012 - $5 million).*

Compensation expense recorded for the year ended December 31, 2014 for RSUs was $5 million (2013 - $5 million; 2012 - $5 million). As of December 31, 2014, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $6 million and is expected to be fully recognized over a weighted average period of approximately two years.

15. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in AOCI for the years ended December 31, 2014, 2013 and 2012, are as follows:

(millions of Canadian dollars)	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
Balance at January 1, 2014	**70**	**(5)**	**-**	**65**
Other comprehensive income retained in AOCI	**(84)**	**3**	**(9)**	**(90)**
Other comprehensive income reclassified to earnings				
Interest rate contracts	**-**	**-**	**-**	**-**
	(84)	**3**	**(9)**	**(90)**
Tax impact				
Income tax on amounts retained in AOCI	**22**	**-**	**2**	**24**
	22	**-**	**2**	**24**
Balance at December 31, 2014	**8**	**(2)**	**(7)**	**(1)**

(millions of Canadian dollars)	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
Balance at January 1, 2013	(10)	(6)	(10)	(26)
Other comprehensive income retained in AOCI	109	1	14	124
Other comprehensive income reclassified to earnings				
Interest rate contracts	(1)	-	-	(1)
	108	1	14	123
Tax impact				
Income tax on amounts retained in AOCI	(28)	-	(4)	(32)
	(28)	-	(4)	(32)
Balance at December 31, 2013	70	(5)	-	65

(millions of Canadian dollars)	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
Balance at January 1, 2012	(11)	(6)	(7)	(24)
Other comprehensive loss retained in AOCI	(1)	-	(4)	(5)
Other comprehensive loss reclassified to earnings				
Interest rate contracts	2	-	-	2
	1	-	(4)	(3)
Tax impact				
Income tax on amounts retained in AOCI	-	-	1	1
	-	-	1	1
Balance at December 31, 2012	(10)	(6)	(10)	(26)

16. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

MARKET RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates and natural gas prices (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them.

Foreign Exchange Risk
Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations in the exchange rate of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is nil (2013 - nil).

Interest Rate Risk
The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to mitigate the volatility of short-term interest rates on interest expense related to variable rate debt.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances. The Company uses qualifying derivative instruments to manage interest rate risk.

Natural Gas Price Risk
Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer, therefore, the net exposure to the Company is nil (2013 - nil).

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges at December 31, 2014 or 2013.

The Company generally has a policy of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2014	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable and other					
Interest rate contracts	**(6)**	**-**	**(6)**	**-**	**(6)**
Other long-term liabilities					
Interest rate contracts	**(5)**	**-**	**(5)**	**-**	**(5)**
Total net derivative liability					
Interest rate contracts	**(11)**	**-**	**(11)**	**-**	**(11)**

December 31, 2013	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts receivable and other					
Interest rate contracts	36	-	36	-	36
Deferred amounts and other assets					
Interest rate contracts	46	-	46	-	46
Total net derivative asset					
Interest rate contracts	82	-	82	-	82

The Company's derivatives instruments mature through 2017 and have a notional principal of $346 million for interest rate contracts for short-term borrowings (2013 - $535 million), and $422 million for interest rate contracts on long-term debt (2013 - $747 million).

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Interest rate contracts	**(84)**	109	(1)
	(84)	109	(1)
Amount of loss reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**-**	(2)	(2)
	-	(2)	(2)
Amount of gains reclassified from AOCI to earnings *(ineffective portion)*			
Interest rate contracts[1]	**-**	2	-
	-	2	-

1 Reported within Interest expense, net in the Consolidated Statements of Earnings.

The Company estimates that $1 million in AOCI related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 25 months at December 31, 2014.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 20 and 21)* as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes, and, if necessary, additional liquidity is available through intercompany transactions with Enbridge Inc. and other related entities. These sources are expected to be sufficient to enable the Company to fund all anticipated requirements. The Company maintains a current shelf prospectus with securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition to the Company's access to the Canadian public capital markets, the Company maintains committed credit facilities *(Note 11)* with a diversified group of banks and institutions. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2014. As a result, all credit facilities are available to the Company and the banks are obligated to fund, and have been funding, the Company under the terms of the facilities.

CREDIT RISK
The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts *(Note 6),* which totaled $33 million at December 31, 2014 (December 31, 2013 - $31 million).

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate.

Entering into derivative financial instruments may also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

The Company had group credit concentration and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments:

	December 31, 2014	December 31, 2013
(millions of Canadian dollars)		
Canadian financial institutions	**-**	69
European financial institutions	**-**	13
	-	82

FAIR VALUE MEASUREMENTS
The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

Fair Value of Derivatives
The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1
Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company does not have any derivative instruments classified as Level 1.

Level 2
Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps for which observable inputs can be obtained.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2014, the Company had Level 2 derivative assets with fair value of nil (2013 - $82 million), and Level 2 derivative liabilities with fair value of $11 million (2013 - nil).

The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at December 31, 2014 or 2013.

Fair Value of Other Financial Instruments
The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted market prices are not available for fair value measurement in which case these investments are recorded at cost. The Company's investment in IPL System Inc., an affiliate company, is recorded at fair value. At December 31, 2014, the fair value of the investment was $825 million (2013 - $825 million). The fair value of the Company's investment is classified as a Level 2 measurement and as of December 31, 2014 and 2013 the fair value approximated its cost and redemption value and therefore no amount was recognized in OCI.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2014, the Company's long-term debt had a carrying value of $3,127 million (2013 - $2,799 million) and a fair value of $3,709 million (2013 - $3,161 million).

The fair value of other financial assets and liabilities other than derivative instruments approximates their cost due to the short period to maturity.

17. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings from continuing operations before income taxes	**252**	260	261
Federal statutory income tax rate	**15.0%**	15.0%	15.0%
Federal income taxes at statutory rate	**38**	39	39
Increase/(decrease) resulting from:			
Provincial and state income taxes	**3**	19	18
Effects of rate regulated accounting[1]	**(25)**	(5)	(7)
Non-taxable intercompany distributions	**(9)**	(9)	(9)
Legislative changes and other rate differentials	**-**	-	8
Intercompany sale of investment[2]	**-**	-	3
Other[3]	**(1)**	(1)	1
Income taxes from continuing operations	**6**	43	53
Effective income tax rate	**2.4%**	16.5%	20.3%

1 *During 2014, previously collected costs for future removal and site restoration were refunded to customers that resulted a decrease in income taxes from continuing operations of $26 million (2013 - nil).*

2 *In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund. As the transaction occurred between entities under common control of Enbridge, the intercompany gain realized as a result of this transfer was eliminated, although cash income taxes of $5 million remained as a charge to earnings.*

3 *Included in "Other" are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals & entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.*

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings from continuing operations before income taxes			
Canada	**249**	258	259
United States	**3**	2	2
	252	260	261
Current income taxes			
Canada	**2**	51	28
United States	**1**	1	1
	3	52	29
Deferred income taxes			
Canada	**3**	(9)	24
United States	**-**	-	-
	3	(9)	24
Income taxes from continuing operations	**6**	43	53

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(577)**	(560)
Financial derivatives	**(3)**	(25)
Deferrals	**-**	(13)
Regulatory assets	**(72)**	(56)
Other	**(1)**	(2)
Total deferred income tax liabilities	**(653)**	(656)
Deferred income tax assets		
Future removal and site restoration reserves	**143**	240
Deferrals	**53**	-
Retirement and postretirement benefits	**21**	23
Other	**4**	1
Total deferred income tax assets	**221**	264
Net deferred income tax liabilities	**(432)**	(392)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 6)*	**23**	2
Deferred amounts and other assets *(Note 8)*	**8**	1
Total deferred income tax assets	**31**	3
Liabilities		
Deferred income taxes	**(463)**	(395)
Total deferred income tax liabilities	**(463)**	(395)
Net deferred income tax liabilities	**(432)**	(392)

The Company has assessed all tax positions. As a result, no significant adjustments were required to be made to the income tax provisions for the year ended December 31, 2014.

The Company has not provided for deferred income taxes on the difference between the carrying value of its foreign subsidiaries and their corresponding tax bases as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying value of the investment and its tax basis is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries is $21 million (2013 - $16 million). If such earning were remitted, in the form of dividends or otherwise, the Company may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

The Company and its subsidiaries are subject to taxation in Canada and the Unites States. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario). The Company's 2010 to 2013 taxation years are still open for audit in Canada.

18. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

The Company maintains a non-contributory basic pension plan that provides either defined benefit or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees.

A measurement date of December 31, 2014 was used to determine the plan assets and accrued benefit obligation for the pension plans.

Defined Benefit Plans
Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation-indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective date of the most recent actuarial valuation was December 31, 2013. The effective date of the next required actuarial valuation is December 31, 2016.

Defined Contribution Plans
Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

OTHER POSTRETIREMENT BENEFITS
The Company also provides OPEB, which primarily includes supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS
The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension		OPEB	
December 31,	**2014**	2013	**2014**	2013
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**875**	905	**100**	112
Service cost	**25**	25	**2**	1
Interest cost	**43**	38	**6**	4
Actuarial loss/(gain)	**142**	(52)	**12**	(16)
Benefits paid	**(41)**	(40)	**(3)**	(2)
Other	**2**	(1)	**-**	1
Benefit obligation at end of year	**1,046**	875	**117**	100
Change in plan assets				
Fair value of plan assets at beginning of year	**866**	782	**9**	7
Actual return on plan assets	**96**	84	**2**	1
Employer's contributions	**41**	38	**5**	3
Benefits paid	**(41)**	(40)	**(3)**	(2)
Other	**(2)**	2	**-**	-
Fair value of plan assets at end of year	**960**	866	**13**	9
Underfunded status at end of year	**(86)**	(9)	**(104)**	(91)
Presented as follows:				
Deferred amounts and other assets *(Note 8)*	**4**	7	**-**	1
Accounts payable and other *(Note 10)*	**-**	-	**(4)**	(4)
Other long-term liabilities *(Note 12)*	**(90)**	(16)	**(100)**	(88)

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
Discount rate	**4.0%**	5.0%	4.3%	**4.0%**	5.0%	4.3%
Average rate of salary increases	**3.7%**	3.5%	3.5%	**3.7%**	3.5%	3.5%

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
(millions of Canadian dollars)						
Benefits earned during the year	**25**	25	21	**1**	1	2
Interest cost on projected benefit obligations	**43**	38	37	**6**	4	4
Expected return on plan assets	**(59)**	(52)	(49)	**(1)**	(1)	(1)
Amortization of prior service costs	**-**	1	1	**-**	-	-
Amortization of actuarial loss	**16**	28	30	**-**	2	1
Net defined benefit costs on an accrual basis	**25**	40	40	**6**	6	6
Defined contribution benefit costs	**1**	1	1	**-**	-	-
Net benefit cost recognized on an accrual basis	**26**	41	41	**6**	6	6
Net amount recognized in OCI						
Net actuarial (gain)/loss[1]	**-**	-	-	**9**	(14)	4
Total amount recognized in OCI	**-**	-	-	**9**	(14)	4
Total net benefit cost on an accrual basis and amount recognized in OCI	**26**	41	41	**15**	(8)	10

1 *Unamortized actuarial losses included in AOCI, before tax, were $9 million relating to OPEB at December 31, 2014 (2013 - nil, 2012 - $14 million).*

The Company estimates that approximately $19 million related to pension plans and OPEB at December 31, 2014 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Actuarial loss	**19**	**-**	**19**
	19	**-**	**19**

Regulatory adjustments were recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers, respectively, in future rates *(Note 4)*. For the year ended December 31, 2014, an offsetting regulatory liability of $6 million (2013 - regulatory asset of $3 million) has been recorded to the extent pension and OPEB costs are expected to be refunded to customers in future rates.

Pension and OPEB costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension and OPEB costs due to the regulatory mechanism in place. As a result, the net pension and OPEB expense primarily consists of OEB approved pension and OPEB costs.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
Discount rate	**5.0%**	4.3%	4.5%	**5.0%**	4.3%	4.5%
Average rate of return on pension plan assets	**6.8%**	6.8%	7.0%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.5%**	3.5%	3.5%	**3.5%**	3.5%	5.0%

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in Which Ultimate Medical Cost Trend Rate Assumption is Achieved
Drugs	7.7%	4.3%	2029
Other medical and dental	4.5%	4.5%	-

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $14 million in the benefit obligation and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $12 million in the benefit obligation and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2014**	2013	**2014**	2013
Expected rate of return	**6.8%**	6.8%	**-**	-

Target Mix for Plan Assets

Equity securities	44.5%
Fixed income securities	40.0%
Other	15.5%

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2014, the pension assets were invested in 55% (2013 - 55%) in equity securities, 36% (2013 - 36%) in fixed income securities and 9% (2013 - 9%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $18 million (2013 - $18 million) have been excluded from the table below.

	2014				2013			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension Benefits								
Cash and cash equivalents	**14**	**-**	**-**	**14**	12	-	-	12
Fixed income securities								
Canadian government real return bonds	**71**	**-**	**-**	**71**	62	-	-	62
Canadian corporate bond index fund	**137**	**-**	**-**	**137**	122	-	-	122
Canadian government bond index fund	**131**	**-**	**-**	**131**	115	-	-	115
Canadian real return bond index fund	**-**	**-**	**-**	**-**	2	-	-	2
Corporate bonds and debentures	**4**	**-**	**-**	**4**	3	-	-	3
United States debt index fund	**2**	**-**	**-**	**2**	1	-	-	1
Equity								
Canadian equity securities	**71**	**-**	**-**	**71**	70	-	-	70
Canadian equity funds	**137**	**-**	**-**	**137**	118	-	-	118
United States equity securities	**1**	**-**	**-**	**1**	1	-	-	1
United States equity funds	**77**	**19**	**-**	**96**	65	17	-	82
Global equity funds	**149**	**63**	**-**	**212**	142	55	-	197
Infrastructure[4]	**-**	**-**	**30**	**30**	-	-	29	29
Real estate[5]	**-**	**-**	**39**	**39**	-	-	38	38
Forward currency contracts	**-**	**(3)**	**-**	**(3)**	-	(4)	-	(4)
OPEB								
Cash and cash equivalents	**1**	**-**	**-**	**1**	-	-	-	-
Fixed income securities								
United States government and government agency bonds	**5**	**-**	**-**	**5**	3	-	-	3
Equity								
United States equity fund	**4**	**-**	**-**	**4**	3	-	-	3
Global equity fund	**3**	**-**	**-**	**3**	3	-	-	3

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair value of the investment in United States Limited Partnership - Global Infrastructure Fund is established through the use of valuation models.
5 The fair value of the investment in Bentall Kennedy Prime Canadian Property Fund Ltd is established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2014**	2013
(millions of Canadian dollars)		
Balance at beginning of year	**67**	53
Unrealized and realized gains	**15**	4
Purchases and settlements, net	**(13)**	10
Balance at end of year	**69**	67

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension		OPEB	
Year ended December 31,	**2014**	2013	**2014**	2013
(millions of Canadian dollars)				
Total contributions	**41**	39	**5**	3
Contributions expected to be paid in 2015	**4**		**5**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2015	2016	2017	2018	2019	2020-2024
(millions of Canadian dollars)						
Expected future benefit payments	46	48	50	53	55	304

19. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Regulatory assets	**(732)**	(31)	(86)
Regulatory liabilities	**(102)**	2	76
Accounts receivable and other[1]	**24**	(13)	73
Gas inventories	**(181)**	(41)	54
Deferred amounts and other assets[1]	**(3)**	(2)	89
Accounts payable and other[1]	**(75)**	80	(59)
Other long-term liabilities[1]	**55**	(81)	(76)
	(1,014)	(86)	71

1 The cash flow impacts of regulatory assets and liabilities have been separately disclosed and are not included.

20. RELATED PARTY TRANSACTIONS

All related party transactions, other than those disclosed under Other Transactions, are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
IPL System Inc. *(Note 16)*			
Dividend income	**63**	63	63
Interest expense	**27**	27	27
Enbridge Inc.			
Purchase of treasury and other management services	**41**	38	39
Interest expense	**2**	-	-
Tidal Energy Marketing Inc.			
Purchase of natural gas	**41**	30	11
Tidal Energy Marketing (U.S.) LLC			
Purchase of natural gas	**57**	21	2
Aux Sable Canada LP			
Purchase of natural gas	**16**	-	-
Gazifère Inc.			
Revenue from wholesale service, including gas sales	**31**	30	25
Vector Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**27**	24	24
Vector Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**2**	2	2
Alliance Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**26**	26	25
Alliance Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**20**	19	18

The Company had related party balances as follows:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**2**	2
Note payable to affiliate company		
Enbridge (U.S.)	**29**	15
Credit facility to affiliate company		
Enbridge Inc.	**175**	-
Other accounts receivable/(payable)		
Enbridge Pipelines Inc.	**(15)**	(15)
Aux Sable Canada LP	**(8)**	-
Enbridge Inc.	**(7)**	(5)
Tidal Energy Marketing Inc.	**(3)**	(7)
Tidal Energy Marketing (U.S.) LLC	**(3)**	(4)
Alliance Pipeline Limited Partnership (Canadian)	**(2)**	(2)
Alliance Pipeline Limited Partnership (U.S.)	**(2)**	(2)
Vector Pipeline Limited Partnership (U.S.)	**(2)**	(2)
IPL System Inc.	**-**	(15)
Gazifère Inc.	**6**	5

Financing Transactions
The Company has invested in Class D, non-voting, redeemable, retractable preference shares of IPL System Inc., an affiliate under common control. At December 31, 2014, the investment of $825 million (2013 - $825 million) in these shares resulted in a weighted average dividend yield of 7.60%.

At December 31, 2014, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.50%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preference shares of the Company. For the year ended December 31, 2014, interest paid amounted to $27 million (2013 - $27 million).

In June 2014, the Company obtained a new $300 million revolving credit facility from Enbridge Inc. which has a term out date in June 2015 and a maturity date in June 2016. At December 31, 2014, the total drawings on the revolving credit facility were $175 million. For the year ended December 31, 2014, interest paid amounted to $2 million (2013 - nil).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 0.55% and is payable on demand.

Treasury and Other Management Services
Enbridge provides treasury and other management services and charges the Company on a cost recovery basis.

Natural Gas Purchases
The Company has contracted for the purchase of natural gas from Aux Sable Canada LP, Tidal Energy Marketing Inc. and Tidal Energy Marketing (U.S.) LLC, related entities under common control, at prevailing market prices and under normal trade terms. Contractual obligations under these contracts are nil.

Wholesale Service
These gas procurement and transportation services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Transportation Services
The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2015 to 2016 - $1,971 million, 2017 to 2018 - $570 million and thereafter - $286 million.

Trade Receivables and Payables
The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is charged. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

Other Transactions
In 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund, an affiliated entity under common control, for cash proceeds of $72 million *(Note 5)*.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

21. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $5,328 million. The amounts which are expected to be paid in the next five years are $1,781 million, $904 million, $589 million, $436 million, and $411 million, respectively, and $1,207 million thereafter.

Minimum future payments under operating leases are estimated at $9 million in aggregate. Estimated annual lease payments for the years ended December 31, 2015 through 2019 are $4 million, $4 million, $1 million, nil and nil, respectively. Total rental expense for operating leases, classified in Operating and administrative expense, was $3 million for each of the years ended December 31, 2014, 2013 and 2012.

CONTINGENCIES

Former Manufactured Coal Gas Plant Sites
The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but the required steps in the discovery process were not completed by the plaintiff. The Company has brought a motion to dismiss the plaintiff's action for delay. At present, it is unknown when or if the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2014 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

OTHER LITIGATON

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

ENBRIDGE GAS DISTRIBUTION INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2015

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Gas Distribution Inc.

Financial Reporting
Management of Enbridge Gas Distribution Inc. (the Company) is responsible for the accompanying consolidated financial statements and all related financial information, including Management's Discussion and Analysis. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, includes directors who are unrelated and independent, and has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with U.S. GAAP and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

(Signed)

Glenn W. Beaumont
President

(Signed)

William M. Ramos
Vice President, Finance & Regulatory

February 18, 2016

February 18, 2016

Independent Auditor's Report

To the Shareholders of
Enbridge Gas Distribution Inc.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2015 and December 31, 2014 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2015, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215, www.pwc.com/ca

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and their subsidiaries as at December 31, 2015 and December 31, 2014 and its results of operations and their cash flows for each of the three years in the period ended December 31, 2015 in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Revenues			
Gas commodity and distribution revenue *(Note 21)*	**3,043**	2,803	2,221
Transportation of gas for customers	**344**	305	328
Other revenue *(Note 21)*	**97**	92	97
	3,484	3,200	2,646
Expenses			
Gas commodity and distribution costs *(Note 21)*	**2,322**	2,046	1,480
Operating and administrative *(Notes 19 and 21)*	**509**	493	496
Depreciation and amortization *(Notes 6 and 8)*	**290**	286	304
Earnings sharing *(Note 4)*	**7**	12	-
	3,128	2,837	2,280
	356	363	366
Other income *(Note 21)*	**70**	66	65
Interest expense, net *(Notes 10, 16 and 21)*	**(181)**	(177)	(171)
	245	252	260
Income taxes *(Note 17)*	**(11)**	(6)	(43)
Earnings	**234**	246	217
Preference share dividends *(Note 13)*	**(2)**	(2)	(2)
Earnings attributable to the common shareholder	**232**	244	215

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Earnings	**234**	246	217
Other comprehensive income/(loss), net of tax *(Notes 15 and 16)*			
Change in unrealized gain/(loss) on cash flow hedges	**(18)**	(62)	81
Reclassification to earnings of realized loss on cash flow hedges	**5**	-	1
Reclassification to earnings of unrealized gain on cash flow hedges	**-**	-	(2)
Actuarial gain/(loss) on other postretirement benefits (OPEB) *(Note 18)*	**-**	(7)	10
Change in foreign currency translation adjustment	**8**	3	1
Other comprehensive income/(loss)	**(5)**	(66)	91
Comprehensive income	**229**	180	308
Preference share dividends	**(2)**	(2)	(2)
Comprehensive income attributable to the common shareholder	**227**	178	306

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Preference shares *(Note 13)*	**100**	100	100
Common shares *(Note 13)*			
Balance at beginning of year	**1,437**	1,287	1,137
Common shares issued	**200**	150	150
Balance at end of year	**1,637**	1,437	1,287
Additional paid-in capital	**1,148**	1,148	1,148
Retained earnings			
Balance at beginning of year	**62**	22	7
Earnings attributable to the common shareholder	**232**	244	215
Common share dividends declared	**(223)**	(204)	(200)
Balance at end of year	**71**	62	22
Accumulated other comprehensive income/(loss) *(Note 15)*			
Balance at beginning of year	**(1)**	65	(26)
Other comprehensive income/(loss)	**(5)**	(66)	91
Balance at end of year	**(6)**	(1)	65
Total shareholders' equity	**2,950**	2,746	2,622

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Operating activities			
Earnings	**234**	246	217
Depreciation and amortization	**290**	286	304
Deferred income taxes	**16**	4	(9)
Refund of revenues *(Note 4)*	**(52)**	52	-
Non-cash net defined pension and OPEB obligations costs	**31**	(5)	2
Premium on issuance of term notes	**-**	-	12
Other	**(2)**	18	10
Changes in operating assets and liabilities *(Notes 3 and 20)*	**325**	(1,031)	(86)
	842	(430)	450
Investing activities			
Additions to property, plant and equipment	**(977)**	(601)	(519)
Additions to intangible assets	**(46)**	(36)	(34)
Change in construction payable	**151**	17	6
Proceeds from disposition	**8**	-	-
	(864)	(620)	(547)
Financing activities			
Change in bank indebtedness *(Note 3)*	**18**	9	(12)
Net change in short-term borrowings *(Note 10)*	**(340)**	564	(210)
Net change in short-term borrowing from affiliates *(Note 21)*	**(170)**	189	2
Term note issuance *(Note 10)*	**558**	729	400
Term note repayments	**(2)**	(400)	-
Common shares issued *(Note 13)*	**200**	150	150
Preference share dividends	**(2)**	(2)	(2)
Common share dividends	**(218)**	(203)	(200)
Other	**(3)**	(2)	(2)
	41	1,034	126
Increase/(decrease) in cash and cash equivalents	**19**	(16)	29
Cash and cash equivalents at beginning of year *(Note 3)*	**17**	33	4
Cash and cash equivalents at end of year	**36**	17	33
Supplementary cash flow information			
Income taxes paid	**17**	23	42
Interest paid *(Note 10)*	**193**	191	169

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2015**	2014
(millions of Canadian dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents *(Note 3)*	**36**	17
Accounts receivable and other *(Notes 4, 5, 16, and 17)*	**790**	1,178
Due from affiliates *(Note 21)*	**10**	11
Gas inventories	**547**	563
	1,383	1,769
Property, plant and equipment, net *(Notes 6 and 12)*	**7,081**	6,268
Investment in affiliate company *(Notes 16 and 21)*	**825**	825
Deferred amounts and other assets *(Notes 4, 7, and 17)*	**556**	738
Intangible assets, net *(Note 8)*	**157**	161
	10,002	9,761
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**27**	9
Short-term borrowings *(Note 10)*	**599**	938
Short-term borrowings from affiliate *(Notes 10 and 21)*	**40**	204
Accounts payable and other *(Notes 3, 4, 9, 16, and 19)*	**870**	861
Due to affiliates *(Note 21)*	**87**	95
Current maturities of long-term debt *(Note 10)*	**2**	2
	1,625	2,109
Long-term debt *(Note 10)*	**3,681**	3,125
Other long-term liabilities *(Notes 4, 11, 12 and 16)*	**847**	943
Deferred income taxes *(Note 17)*	**524**	463
Loans from affiliate company *(Notes 10 and 21)*	**375**	375
	7,052	7,015
Commitments and contingencies *(Notes 21 and 22)*		
Shareholders' equity		
Share capital *(Note 13)*		
Preference shares *(convertible; 4 outstanding at December 31, 2015 and 2014)*	**100**	100
Common shares *(170 and 159 outstanding at December 31, 2015 and 2014, respectively)*	**1,637**	1,437
Additional paid-in capital	**1,148**	1,148
Retained earnings	**71**	62
Accumulated other comprehensive loss *(Note 15)*	**(6)**	(1)
	2,950	2,746
	10,002	9,761

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

(Signed)

Glenn W. Beaumont
President

(Signed)

J. Herb England
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. The Company is permitted to prepare its consolidated financial statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under an exemption granted by securities regulators in Canada until 2018.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 4)*; unbilled revenues *(Note 5)*; allowance for doubtful accounts *(Note 5)*; carrying value of gas inventory; depreciation rates and carrying value of property, plant and equipment *(Note 6)*; amortization rates and carrying value of intangible assets *(Note 8)*; valuation of stock-based compensation *(Note 14)*; fair value of financial instruments *(Note 16)*; provisions for income taxes *(Note 17)*; assumptions used to measure retirement and OPEB *(Note 18);* commitments and contingencies *(Note 22)*; and fair value of asset retirement obligations (ARO) *(Note 12)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its subsidiary. All significant intercompany accounts and transactions are eliminated upon consolidation.

REGULATION

The utility operations of the Company, excluding St. Lawrence, are regulated by the Ontario Energy Board (OEB) and the utility operations of St. Lawrence are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities *(Note 4)*.

REVENUE RECOGNITION

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise areas.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

PUSH-DOWN ACCOUNTING
The Company elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted U.S. GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by the Company. Upon adopting push-down accounting, the historical cost of the Company's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships
The Company uses derivative financial instruments to manage its exposure to changes in interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges at December 31, 2015 or 2014.

Cash Flow Hedges
The Company uses cash flow hedges to manage its exposure to changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/loss (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives
The Company recognizes the fair value of derivative instruments on the Consolidated Statements of Financial Position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with Deferred amounts and other assets. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

INCOME TAXES
The liability method of accounting for income taxes is followed. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in income taxes.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as approved by the Regulators for rate-making purposes. As a result, rates do not include the recovery of deferred income taxes related to temporary differences. A corresponding deferred income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates (*Note 4*).

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Consolidated Statement of Financial Position. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. The effects of translating the financial statements of St. Lawrence to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI). Asset and liability accounts are translated at the exchange rates in effect on the date of the Consolidated Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased. Refer to Note 3 for changes in accounting policy.

GAS INVENTORIES
Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates authorized by the Regulators. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the Regulators. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation until the last asset in the pool is disposed of. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily include: costs which the Regulators have permitted, or are expected to permit, to be recovered through future rates; deferred income taxes; derivative financial instruments; and deferred financing costs.

INTANGIBLE ASSETS
Intangible assets consist primarily of the Company's Customer Information System (CIS) and software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS
The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. In 2014, new mortality assumptions were issued and further revised in 2015. These assumptions were adopted by the Company for the measurement of the December 31, 2015 benefit obligations. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contributions occur.

The Company also provides OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities, respectively, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

The Company records regulatory adjustments to reflect the difference between pension expense and OPEB costs for accounting purposes and the pension expense and OPEB costs for rate-making purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension expense or OPEB costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation accounting, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION

Enbridge grants stock-based compensation to certain employees and senior officers of the Company through four long-term incentive compensation plans. Compensation expense associated with each of the plans, as determined under the methods outlined below is recognized in Operating and administrative expense. Amounts owing to Enbridge in respect of stock-based compensation are payable on a quarterly basis.

Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISOs granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of the Company's shares. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

Performance Stock Options (PSO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the PSOs granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period. The options become exercisable when both performance targets and the time vesting requirements have been met.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

FUTURE ACCOUNTING POLICY CHANGES

Measurement Date of Defined Benefit Obligation and Plan Assets

Accounting Standards Update (ASU) 2015-04 was issued in April 2015 with the intent to simplify the fair value measurement of defined benefit plan assets and obligations. Where there are significant events in an interim period that would trigger a re-measurement of the plan assets and obligations, an entity is permitted to re-measure such assets and obligations using the month end that is closest to the date of the significant event. The accounting update is effective for financial statements issued for fiscal years beginning after December 15, 2015 and is to be applied on a prospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs
ASU 2015-03 was issued in April 2015 with the intent to simplify the presentation of debt issuance costs. The new standard requires a debt issuance cost related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, as consistent with the presentation of debt discounts or premiums. Further, ASU 2015-15 was issued in August 2015 to clarify the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements, whereby the Company may defer debt issuance costs as an asset and subsequently amortize them over the term of the line-of-credit. The accounting updates are effective for financial statements issued for fiscal years beginning after December 15, 2015 on a retrospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Revenue from Contracts with Customers
ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. In July 2015, the effective date of the new standard was delayed by one year and the new standard is now effective for annual and interim periods beginning on or after December 15, 2017 and may be applied on either a full or modified retrospective basis. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

Classification of Deferred Taxes on the Statement of Financial Position
ASU 2015-17 was issued in November 2015 with the intent to simplify the presentation of deferred income taxes. The amendments eliminate the current requirement to present deferred tax assets and liabilities as current and noncurrent. The amendments require that all deferred tax assets and liabilities be classified as noncurrent in a classified statement of financial position. The accounting update is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years and is to be applied on a prospective basis. Early application is permitted for all entities as of the beginning of an interim or annual reporting period. Effective January 1, 2016, the Company will elect to early adopt ASU 2015-17. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Recognition and Measurement of Financial Assets and Liabilities
ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation, and disclosure of financial assets and liabilities. The amendments revise accounting related to the classification and measurement of investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value, and the disclosure requirements associated with the fair value of financial instruments. The accounting update is effective for fiscal years beginning after December 15, 2017, and is to be applied by means of a cumulative-effect adjustment to the consolidated Statement of Financial Position as of the beginning of the fiscal year of adoption, with amendments related to equity securities without readily determinable fair values to be applied prospectively. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

Simplifying the Measurement of Inventory
ASU 2015-11 was issued in July 2015 with the intent to simplify the measurement of inventory. The new standard requires inventory to be measured at the lower of cost and net realizable value and is applicable to all inventory, with the exception of inventory measured using last-in, first-out or the retail inventory method. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim reporting periods beginning after December 15, 2016 and is to be applied on a prospective basis.

CHANGES IN ACCOUNTING POLICY

Book Overdrafts
Prior to January 2015, the Company recorded all obligations for which cheques were issued but not presented to the financial institution in Accounts payable and other. Effective January 2015, the Company changed the accounting policy and began presenting only book overdrafts in Accounts payable and other. Comparative figures presented in the audited consolidated financial statements for the year ended December 31, 2015 have been retrospectively revised. The change in accounting policy did not have a material impact on the audited Consolidated Statements of Financial Position and audited Consolidated Statements of Cash Flows for previously issued financial statements. There was no impact to the audited Consolidated Statement of Earnings. The change in accounting policy allows for the Company to account for its book overdrafts in a preferable method.

4. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

For the purposes of this note, “Enbridge Gas Distribution” refers specifically to Enbridge Gas Distribution Inc. excluding St. Lawrence, whereas “St. Lawrence” refers specifically to St. Lawrence Gas Company, Inc.

RECENT RATE APPROVALS

Enbridge Gas Distribution
For the year ended December 31, 2015, Enbridge Gas Distribution’s rates were set according to the OEB approved settlement agreement (April 2015) and final rate order (May 2015). The rates approved as part of the 2015 rate application represented the second year of the Company’s customized incentive regulation (IR) plan, which set rates for the period of 2014 to 2018 and was approved by the OEB in July and August 2014.

For the year ended December 31, 2014, Enbridge Gas Distribution’s rates were set by the OEB’s July 2014 decision, and subsequent August 2014 decision and rate order in the Company’s customized IR application. The decisions and rate order established final 2014 allowed revenues and billing rates, as well as placeholder allowed revenues for 2015 through 2018. The customized IR plan requires Enbridge Gas Distribution to update select items in each of 2015 through 2018, in order to establish final allowed revenues and rates. The customized IR decision also approved the adoption of a new approach for determining net negative salvage percentages as a component of the Enbridge Gas Distribution’s depreciation rates in addition to Enbridge Gas Distribution shares earnings above the approved base return, equally with customers.

Under the customized IR plan, the Company has continued to apply the accounting guidance found in Accounting Standards Codification (ASC) 980 – Regulated Operations.

For the year ended December 31, 2013, Enbridge Gas Distribution’s rates were set on a cost of service (COS) basis pursuant to an OEB approved settlement agreement.

St. Lawrence Gas
For the years ended December 31, 2015, 2014 and 2013, St. Lawrence’s rates were set using a COS methodology. Under COS, revenues are set to recover costs and to earn a rate of return on the deemed common equity component of rate base. Costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, interest and income taxes. Rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Gas costs are not recovered through revenue rates, but are set separately in gas cost rates.

Under COS, it is the responsibility of Enbridge Gas Distribution and St. Lawrence to demonstrate to the Regulators the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken.

During the years ended December 31, 2015, 2014 and 2013, the cost of natural gas was passed on to customers as a flow-through.

APPROVED RETURNS ON EQUITY

Enbridge Gas Distribution

Enbridge Gas Distribution's rates for 2015 included an after-tax rate of return on common equity of 9.30% (2014 - 9.36% and 2013 - 8.93%) based on a 36% (2014 and 2013 - 36%) deemed common equity component of rate base.

St. Lawrence

St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 10.5% for the year ended December 31, 2015 (2014 and 2013 - 10.5%) based on a 50% (2014 and 2013 - 50%) deemed common equity component of rate base. Any earnings above a return on equity of 11% (2014 and 2013 - 11%) were shared equally with customers. The calculation of such earnings was cumulative from January 1, 2010 to December 31, 2015 and resulted in no sharing impact as at December 31, 2015 (2014 and 2013 - nil).

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities

As a result of rate regulation accounting, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation accounting, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. The Regulators' future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

FINANCIAL STATEMENT EFFECTS

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	**2015**	2014	Consolidated Statement of Financial Position Location**	Estimated Recovery/ Settlement Period *(years)*
(millions of Canadian dollars)				
Regulatory assets/(liabilities)				
Enbridge Gas Distribution				
Deferred income taxes[1]	**324**	270	AP/DA	*
Purchased gas variance[2]	**129**	673	AR	1
OPEB[3]	**75**	84	AR/DA	17
Unabsorbed demand cost[4]	**66**	14	AR	*
Constant dollar net salvage adjustment[5]	**42**	37	DA	*
Pension plans, net[6]	**30**	90	DA/OLTL	*
Customer care CIS rate smoothing deferral[7]	**9**	8	AR/DA	3
Demand side management incentive[8]	**8**	13	AR	*
Storage and transportation deferral[9]	**5**	(3)	AR	1
Unaccounted for gas variance[10]	**3**	13	AR	1
Design day criteria transportation[11]	**-**	13	-	*
Revenue adjustment[12]	**-**	(52)	-	*
Future removal and site restoration reserves[13]	**(553)**	(536)	OLTL	*
Site restoration clearance adjustment[14]	**(193)**	(283)	AP/OLTL	3
Transactional services deferral[15]	**(9)**	(26)	AP	1
Earnings sharing deferral[16]	**(6)**	(12)	AP	*
Average use true-up variance[17]	**(2)**	1	AP	1
Post-retirement true-up variance[18]	**(1)**	(3)	AP	*
Other regulatory assets and liabilities, net	**3**	(1)	***	***
	(70)	300		
St. Lawrence				
Other regulatory assets and liabilities, net	**6**	5	***	***
	(64)	305		

* Refer to the footnote for details

** AR – Accounts receivable and other
AP – Accounts payable and other
DA – Deferred amounts and other assets
OLTL – Other long-term liabilities

*** Dependent on the nature of the item

1 *The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate regulation accounting, this regulatory balance and the related earnings impact would not be recorded.*

2 *Purchased gas variance (PGVA) is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. In the absence of rate regulation accounting, the actual cost of natural gas would be included in Gas commodity and distribution costs, and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established.*

3 *The OPEB balance represents the Company's right to recover OPEB costs pursuant to an OEB rate order, which allows the amount as at December 31, 2013 to be collected in rates over a 20-year period commencing in 2013. In the absence of rate regulation accounting, this regulatory balance and related earnings impact would not be recorded.*

4 *The Unabsorbed demand cost deferral account (UDCDA) represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet requirements resulting from its Peak Gas Design Day Criteria (PGDDC). Enbridge Gas Distribution updated its PGDDC in 2013 and 2014. The impact of this update was phased in equally over the two years.*

The balance for 2014 captures the cost consequences of unutilized transportation capacity above the amount associated with the 2014 Design day criteria transportation deferral account (DDCTDA). In the absence of rate regulation accounting, these costs would be expensed as incurred.

5 *The Constant dollar net salvage adjustment represents the cumulative variance between the amount proposed for clearance and the actual amount cleared, relating specifically to the site restoration clearance adjustment. At the end of 2018 any residual balance will be cleared in a post 2018 true up, ensuring that the actual amount cleared is equivalent to the required $380 million.*

6 *The pension plan balance represents the regulatory offset to the pension liability/asset to the extent the amounts are to be collected/refunded in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation accounting, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

7 *Customer care CIS rate smoothing deferral represents the difference between the forecast costs and the approved costs for customer care and CIS reflected in rates. The balance accumulated during 2013 to 2015 when the cost per customer exceeds the cost approved for recovery in rates. The balance will be drawn down during 2016 to 2018 when the cost per customer will be lowered than the cost approved for recovery in rates. Enbridge Gas Distribution has received OEB approval to collect from or refund to customers any remaining balance after 2018. In the absence of rate regulation accounting, the variance would be included in earnings in the year incurred.*

8 *Demand side management incentive deferral account (DSMIDA) represents the benefit derived by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the DSMIDA amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

9 *Storage and transportation deferral represents the difference between the actual cost and the approved cost of natural gas storage and transportation reflected in rates. Enbridge Gas Distribution has historically been granted OEB approval to collect this balance from or to refund this balance to customers, generally in the subsequent year. In the absence of rate regulation accounting, the actual cost of natural gas storage and transportation would be included in Gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount, as the right to collect or refund the revenue or costs has been established.*

10 *Unaccounted for gas variance represents the difference between the total natural gas distributed by Enbridge Gas Distribution and the amount of natural gas billed or billable to customers for their recorded consumption, to the extent it is different from the approved amount built into rates. Enbridge Gas Distribution has deferred unaccounted for gas variance and has historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation accounting, this variance would be included in earnings in the year incurred.*

11 *DDCTDA balance represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet increased requirements resulting from the PGDDC. Enbridge Gas Distribution updated its PGDDC in 2013 and 2014. The impact of this update was phased in equally over the two years. The heating degree days used within its design day criteria for 2013 and 2014's design day criteria were updated. The balance for 2014 captures the cost consequences of unutilized transportation capacity associated with the 2014 DDCTDA. In the absence of rate regulation accounting, these costs would be expensed as incurred.*

12 *The revenue adjustment represents the revenue variance between interim rates, which were in place from January 2014 to September 2014, and the final OEB approved 2014 rates, which were implemented in October 2014, but effective in January 2014. The revenue adjustment balance is the 2014 OEB approved revenue adjustment amount that was refunded to customers in January 2015. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

13 *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment that is recorded in rates. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation accounting, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

14 *The Site restoration clearance adjustment represents the amount, that was determined by the OEB, of previously collected costs for future removal and site restoration that is now considered to be in excess of future requirements and will be refunded to customers over the customized IR term. This was a result of the OEB's approval of the adoption of a new approach for determining net negative salvage percentages. The new approach resulted in lower depreciation rates and lower future removal and site restoration reserves. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

15 *Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

16 *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the customized IR plan. The Earnings sharing is payable to customers and represents 50% of normalized U.S. GAAP utility earnings represented by an ROE in*

excess of the allowed utility ROE applicable to Enbridge Gas Distribution, as determined for each year of the customized IR plan. There would be no change in the treatment of this item in the absence of rate regulation accounting.

17 *Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual weather normalized average use for general service customers. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation accounting, this regulatory balance and the related earnings impact would not be recorded.*

18 *Post-retirement true-up variance is the difference between the actual cost and the approved cost of pension and OPEB reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers in the subsequent year, up to a maximum of $5 million per year. Any amounts in excess of $5 million per year will be deferred for refund or collection in the next subsequent year. In the absence of rate regulation accounting, the variance would be included in earnings in the year incurred.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Revenue
To recognize the actions or expected actions of the Regulators, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

Operating Cost Capitalization
With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation accounting, a portion of such operating costs would be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2015, cumulative costs relating to this services contract of $174 million (2014 - $166 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation accounting, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment
In the absence of rate regulation accounting, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred. Further, on the retirement of utility assets, the excess of the book value net of proceeds would be recorded as a loss on the sale/disposal of assets in earnings in the period of retirement. Any removal costs incurred would be booked against the future removal and site restoration balance (described above).

Intangible Assets
The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2015, the net book value of these costs was $48 million (2014 - $60 million). In the absence of rate regulation accounting, a portion of the original cost of these assets would have been expensed in the period incurred.

Gas Inventories
Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. Included in gas inventories at December 31, 2015 is $40 million (2014 - $42 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation accounting, these costs would be expensed as incurred and inventory would be recorded at the lower of cost or market value.

Depreciation
In the absence of rate regulation accounting, depreciation rates would not have included a charge for future removal and site restoration costs.

5. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2015**	2014
(millions of Canadian dollars)		
Trade receivables	**309**	372
Regulatory assets *(Note 4)*	**216**	567
Unbilled revenues	**151**	161
Agent billing and collection receivable	**39**	-
Sundry receivables	**28**	22
Taxes receivable	**19**	28
Current deferred income taxes *(Note 17)*	**18**	23
Prepaid expenses	**11**	8
Other	**33**	30
Allowance for doubtful accounts *(Note 16)*	**(34)**	(33)
	790	1,178

During the first half of 2014, increases in natural gas prices and colder than normal weather resulted in the Company accumulating a significant balance in its PGVA. Included in Regulatory assets as at December 31, 2015 is $129 million (December 31, 2014 - $491 million) which represents the PGVA balance that is expected to be recovered from customers within the next 12 months.

6. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2015**	2014
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	**2.2%**	**3,740**	3,593
Gas services	**2.3%**	**2,929**	2,798
Regulating and metering equipment	**5.7%**	**848**	825
Gas storage	**2.1%**	**327**	323
Right-of-way	**1.0%**	**52**	52
Computer technology	**37.5%**	**31**	40
Under construction	**-**	**893**	307
Construction materials inventory	**-**	**40**	39
Land	**-**	**24**	24
Other	**6.9%**	**303**	289
		9,187	8,290
Accumulated depreciation		**(2,197)**	(2,115)
		6,990	6,175
Unregulated property, plant and equipment			
Gas storage	**2.1%**	**88**	88
Other	**8.6%**	**27**	27
		115	115
Accumulated depreciation		**(24)**	(22)
		91	93
Property, plant and equipment, net		**7,081**	6,268

Depreciation expense, including amounts collected for future removal and site restoration costs, was $239 million for the year ended December 31, 2015 (2014 - $237 million, 2013 - $267 million).

7. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2015**	2014
(millions of Canadian dollars)		
Regulatory assets *(Note 4)*	**526**	711
Deferred financing costs	**13**	12
Pension and OPEB asset *(Note 18)*	**8**	4
Deferred income taxes *(Note 17)*	**8**	8
Other	**1**	3
	556	738

At December 31, 2015, deferred financing costs of $29 million (2014 - $34 million) were subject to amortization and are presented net of accumulated amortization of $16 million (2014 - $22 million). Amortization expense for the year ended December 31, 2015 was $2 million (2014 and 2013 - $2 million).

In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. Included in Regulatory assets at December 31, 2015 is nil (2014 - $182 million) which represents the portion of the PGVA balance that is expected to be recovered beyond the next 12 months.

8. INTANGIBLE ASSETS

December 31, 2015	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**23.2%**	**238**	**(129)**	**109**
CIS	**10.0%**	**127**	**(79)**	**48**
		365	**(208)**	**157**

December 31, 2014	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	24.1%	198	(97)	101
CIS	10.0%	127	(67)	60
		325	(164)	161

Intangible assets include $61 million of work-in-progress as at December 31, 2015 (2014 - $23 million). Total amortization expense for intangible assets was $51 million for the year ended December 31, 2015 (2014 - $49 million, 2013 - $37 million). The Company expects aggregate amortization expense for the years ending December 31, 2016 through 2020 of $58 million, $47 million, $45 million, $41 million and $32 million, respectively.

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2015**	2014
(millions of Canadian dollars)		
Accrued liabilities	**396**	351
Regulatory liabilities *(Note 4)*	**136**	233
Budget billing plan payable	**105**	137
Trade payables	**62**	17
Security deposits	**61**	61
Contractual holdbacks	**38**	7
Interest payable	**33**	27
Short-term portion of derivative liabilities *(Note 16)*	**14**	6
Taxes payable	**9**	11
Current portion of OPEB liability *(Note 18)*	**4**	4
Agent billing and collection payable	**-**	2
Dividends payable	**1**	1
Other	**11**	4
	870	861

Included in Regulatory liabilities at December 31, 2015 is $84 million (2014 - $90 million) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers within the next 12 months. Also included in Regulatory liabilities at December 31, 2015 is nil (2014 - $52 million) relating to the refund of revenues to customers.

10. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2015**	2014
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	85
Medium-term notes	4.56%	2017-2050	**3,595**	3,025
Commercial paper and credit facility draws, net[1]			**607**	1,122
Other[2]			**35**	37
Total debt			**4,322**	4,269
Current maturities			**(2)**	(2)
Short-term borrowings	0.81%		**(599)**	(938)
Short-term borrowings from affiliates *(Note 21)*	0.80%		**(40)**	(204)
Long-term debt			**3,681**	3,125
Loans from affiliate company *(Note 21)*			**375**	375

1 *Includes amounts drawn on uncommitted demand credit facilities.*
2 *Consists of note payable to affiliate company and debt premium.*

In September 2015, the Company issued $400 million of 10-year medium-term notes at an interest rate of 3.31% and an additional $170 million of medium-term notes under the same terms as the August 2044 30-year medium-term note pricing supplement issued in August 2014 at an interest rate of 4.00%.

In December 2015, a new $1.5 billion shelf prospectus was filed as a continuation of the Company's medium-term note program, which was previously renewed in June 2014. The prospectus is effective for a 25-month period.

For the years ending December 31, 2016 through 2020, medium-term note maturities are $2 million, $502 million, $2 million, $2 million and $400 million, respectively. The Company's debentures and medium-term notes bear interest at fixed rates, and interest obligations for the years ending December 31, 2016 through 2020 are $171 million, $169 million, $156 million, $156 million and $155 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Debentures and medium-term notes	**158**	149	138
Loans from affiliate company *(Note 21)*	**27**	29	27
Commercial paper and credit facility draws	**8**	9	4
Other interest and finance costs	**9**	(4)	9
Capitalized	**(21)**	(6)	(7)
	181	177	171

In 2015, total interest paid to third parties was $166 million (2014 - $163 million, 2013 - $142 million) and total interest paid to affiliate company and related party was $27 million (2014 - $29 million, 2013 - $27 million).

The Company's borrowings, whether debentures or medium-term notes, are unsecured. As at December 31, 2015, the Company was in compliance with all covenants.

CREDIT FACILITIES

The Company currently has a $1 billion commercial paper program limit that is backstopped by committed lines of credit of $1 billion. The term of any commercial paper issued under this program may not exceed one year. The maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option. In July 2015, the Company extended the term out date of this external credit facility to July 2016, with a maturity date in July 2017.

The Company also has a $300 million revolving credit facility from Enbridge. In June 2015, the Company extended the term out date to May 2016 on this revolving credit facility, with a maturity date in May 2017. As at December 31, 2015, no amounts were drawn on this credit facility.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details on the Company's committed credit facilities as at December 31.

		December 31, 2015			December 31, 2014
	Maturity Dates	Total Facilities[1]	Draws[2]	Available	Total Facilities[1]
(millions of Canadian dollars)					
Enbridge Gas Distribution Inc.	2017	**1,300**	**595**	**705**	1,300
St. Lawrence Gas Company, Inc.	2019	**10**	**8**	**2**	8
Total credit facilities		**1,310**	**603**	**707**	1,308

1 *Includes a $300 million revolving credit facility from the Company's ultimate parent, Enbridge and matures in May 2017.*
2 *Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the external credit facility.*

In addition to the committed credit facilities noted above, St. Lawrence also has $7 million (2014 - $6 million) of uncommitted demand credit facilities, of which $3 million (2014 - $2 million) was unutilized as at December 31, 2015.

Credit facilities carried a weighted average standby fee of 0.2% on the unused portion and draws bear interest at market rates.

11. OTHER LONG-TERM LIABILITIES

December 31,	**2015**	2014
(millions of Canadian dollars)		
Regulatory liabilities *(Note 4)*	**670**	740
Pension and OPEB liabilities *(Note 18)*	**163**	190
Long-term portion of derivative liabilities *(Note 16)*	**-**	5
Other *(Note 12)*	**14**	8
	847	943

Included in Regulatory liabilities at December 31, 2015 is $109 million (2014 - $193 million) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers beyond the next 12 months.

12. ASSET RETIREMENT OBLIGATIONS

The liability for the expected cash flows as recognized in the consolidated financial statements reflected discount rates ranging from 1.65% to 3.77% (2014 - 1.65% to 3.77%). A reconciliation of movements in the Company's ARO is as follows:

December 31,	**2015**	2014
(millions of Canadian dollars)		
Obligations at beginning of year	**9**	6
Liabilities settled	**(2)**	-
Change in estimate	**2**	3
Accretion expense	**-**	-
Obligations at end of year	**9**	9
Presented as follows:		
Other long-term liabilities *(Note 11)*	**9**	9
	9	9

13. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preference shares.

COMMON SHARES

	2015		2014		2013	
December 31,	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**158.9**	**1,437**	150.6	1,287	142.3	1,137
Common shares issued	**11.1**	**200**	8.3	150	8.3	150
Balance at end of year	**170.0**	**1,637**	158.9	1,437	150.6	1,287

PREFERENCE SHARES

December 31, 2015, 2014, and 2013	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preference shares in millions)			
Group 1	0.2	-	-
Group 2, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 2, Series D, Cumulative Redeemable Convertible	4	-	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	-	-
Group 5	10	-	-
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preference shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case. As at December 31, 2015, no preference shares have been redeemed.

On July 1, 2019, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference shares on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period. The Group 3, Series D preference shareholders opted not to convert their shares into Group 2, Series D preference shares effective July 1, 2014.

The Group 2, Series D preference shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder's option on July 1, 2019 and every five years thereafter.

14. STOCK OPTION AND STOCK UNIT PLANS

Enbridge's four long-term incentive compensation plans include the ISO Plan, the PSO Plan, the PSU Plan and the RSU Plan. The Company reimburses Enbridge for stock-based compensation costs associated with its employees on a quarterly basis. As of December 31, 2015, the Company did not have any employees that had options in the PSO Plan.

INCENTIVE STOCK OPTIONS

Key employees of the Company are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2015	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**2,665**	**33.53**		
Options granted	**458**	**59.08**		
Options exercised[1]	**(422)**	**23.20**		
Options cancelled	**(16)**	**44.94**		
Employee movements from other Enbridge companies	**3**	**18.24**		
Options outstanding at end of year	**2,688**	**39.43**	**6.3**	**45**
Options vested at end of year[2]	**1,560**	**30.85**	**4.9**	**40**

1 The total intrinsic value of ISOs exercised during the year ended December 31, 2015 was $14 million (2014 - $11 million; 2013 - $7 million) and cash received by Enbridge on exercise was $10 million (2014 - $5 million; 2013 - $2 million).
2 The total fair value of options vested under the ISO Plan during the year ended December 31, 2015 was $2 million (2014 and 2013 - $2 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2015**	2014	2013
Fair value per option *(Canadian dollars)*[1]	**6.48**	5.53	5.27
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	5
Expected volatility[3]	**19.9%**	16.9%	17.4%
Expected dividend yield[4]	**3.2%**	2.9%	2.8%
Risk-free interest rate[5]	**0.9%**	1.6%	1.2%

1 Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $6.22 (2014 - $5.45; 2013 - $5.15) for Canadian employees and US$6.22 (2014 - US$5.35, 2013 - US$5.63) for United States employees.
2 The expected option term is based on historical exercise practice.
3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.
4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.
5 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.

Compensation expense recorded for the year ended December 31, 2015 for ISOs was $4 million (2014 - $4 million; 2013 - $3 million). At December 31, 2015, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $4 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan for senior officers of the Company where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two if Enbridge performs within the highest range of its performance targets. The 2013, 2014 and 2015 grants derive the performance multiplier through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's earnings per share, adjusted for unusual non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2015 expense, multipliers of two, based upon multiplier estimates at December 31, 2015, were used for each of the 2013, 2014 and 2015 PSU grants.

December 31, 2015	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**26**		
Units granted	**14**		
Units matured[1]	**(11)**		
Dividend reinvestment	**1**		
Units outstanding at end of year	**30**	**1.5**	**3**

1 *The total amount paid by Enbridge during the year ended December 31, 2015 for PSUs was $2 million (2014 - $1 million; 2013 - $2 million).*

Compensation expense recorded for the year ended December 31, 2015 for PSUs was $2 million (2014 - $5 million; 2013 - $4 million). As of December 31, 2015, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $2 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a RSU Plan where cash awards are paid to certain non-executive employees of the Company following a 35-month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2015	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**196**		
Units granted	**81**		
Units cancelled	**(9)**		
Units matured[1]	**(96)**		
Dividend reinvestment	**10**		
Employee movements from other Enbridge companies	**2**		
Units outstanding at end of year	**184**	**1.4**	**11**

1 *The total amount paid by Enbridge during the year ended December 31, 2015 for RSUs was $5 million (2014 and 2013 - $5 million).*

Compensation expense recorded for the year ended December 31, 2015 for RSUs was $6 million (2014 and 2013 - $5 million). As of December 31, 2015, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $6 million and is expected to be fully recognized over a weighted average period of approximately two years.

15. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in AOCI for the years ended December 31, 2015, 2014 and 2013, are as follows:

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2015	**8**	**(2)**	**(7)**	**(1)**
Other comprehensive income retained in AOCI	**(24)**	**8**	**-**	**(16)**
Other comprehensive loss reclassified to earnings	**6**	**-**	**-**	**6**
Income tax on amounts retained in AOCI	**6**	**-**	**-**	**6**
Income tax on amounts reclassified to earnings	**(1)**	**-**	**-**	**(1)**
	(13)	**8**	**-**	**(5)**
Balance at December 31, 2015	**(5)**	**6**	**(7)**	**(6)**

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(*millions of Canadian dollars*)				
Balance at January 1, 2014	70	(5)	-	65
Other comprehensive income/(loss) retained in AOCI	(84)	3	(9)	(90)
Other comprehensive income reclassified to earnings	-	-	-	-
Income tax on amounts retained in AOCI	22	-	2	24
	(62)	3	(7)	(66)
Balance at December 31, 2014	8	(2)	(7)	(1)

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(*millions of Canadian dollars*)				
Balance at January 1, 2013	(10)	(6)	(10)	(26)
Other comprehensive income retained in AOCI	109	1	14	124
Other comprehensive loss reclassified to earnings	(1)	-	-	(1)
Income tax on amounts retained in AOCI	(28)	-	(4)	(32)
	80	1	10	91
Balance at December 31, 2013	70	(5)	-	65

16. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

MARKET RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates and natural gas prices (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates.

The Company generates certain revenues, and holds a subsidiary that is denominated in a currency other than Canadian dollars. As a result, the Company's earnings, cash flows, and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations in the exchange rate of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer;

therefore, the Company has no net exposure to movements in the foreign exchange rate on natural gas purchases.

Interest Rate Risk
The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to mitigate the volatility of short-term interest rates on interest expense related to variable rate debt.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances. The Company uses qualifying derivative instruments to manage interest rate risk.

The Company's portfolio mix of fixed and variable rate debt instruments is monitored by its ultimate parent company, Enbridge. The Company does not typically manage the fair value of its debt instruments.

Natural Gas Price Risk
Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer, therefore, the net exposure to the Company is nil (2014 - nil).

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value or net investment hedges at December 31, 2015 or 2014.

The Company generally has a common practice of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2015	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable and other					
Interest rate contracts	**(14)**	**-**	**(14)**	**-**	**(14)**
Other long-term liabilities					
Interest rate contracts	**-**	**-**	**-**	**-**	**-**
Total net derivative liability					
Interest rate contracts	**(14)**	**-**	**(14)**	**-**	**(14)**

December 31, 2014	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable and other					
Interest rate contracts	(6)	-	(6)	-	(6)
Other long-term liabilities					
Interest rate contracts	(5)	-	(5)	-	(5)
Total net derivative liability					
Interest rate contracts	(11)	-	(11)	-	(11)

The Company's derivatives instruments mature through 2017 and have a notional principal of $154 million for interest rate contracts for short-term borrowings (2014 - $346 million), and $162 million for interest rate contracts on long-term debt (2014 - $422 million).

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Amount of unrealized (loss)/gain recognized in OCI			
Cash flow hedges			
Interest rate contracts	**(24)**	(84)	109
	(24)	(84)	109
Amount of loss reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**(2)**	-	(2)
	(2)	-	(2)
Amount of (loss)/gain reclassified from AOCI to earnings *(ineffective portion)*			
Interest rate contracts[1]	**(4)**	-	2
	(4)	-	2

1 Reported within Interest expense, net in the Consolidated Statements of Earnings.

The Company estimates that $3 million in AOCI related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 13 months at December 31, 2015.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 21 and 22)* as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes, and, if necessary, additional liquidity is available through intercompany transactions with its ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable the Company to fund all anticipated requirements. The Company maintains a current MTN shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. In addition to the Company's access to the Canadian public capital markets, the Company maintains committed credit facilities *(Note 10)* with a diversified group of banks and institutions. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2015. As a result, all credit facilities are available to the Company and the banks are obligated to fund, and have been funding, the Company under the terms of the facilities.

CREDIT RISK

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts *(Note 5),* which totaled $34 million at December 31, 2015 (December 31, 2014 - $33 million).

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate.

Entering into derivative financial instruments may also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

The Company did not have group credit concentration and maximum credit exposure, with respect to derivative instruments, in the Canadian financial institutions or European financial institutions counterparty segments at December 31, 2015 and 2014.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

Fair Value of Derivatives

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company does not have any derivative instruments classified as Level 1.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps for which observable inputs can be obtained.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2015, the Company had Level 2 derivative assets with fair value of nil (2014 - nil), and Level 2 derivative liabilities with fair value of $14 million (2014 - $11 million).

The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at December 31, 2015 or 2014.

Fair Value of Other Financial Instruments
The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted market prices are not available for fair value measurement in which case these investments are recorded at cost. The Company's investment in IPL System Inc., an affiliate company, is recorded at fair value. At December 31, 2015, the fair value of the investment was $825 million (2014 - $825 million). The fair value of the Company's investment is classified as a Level 2 measurement and as of December 31, 2015 and 2014 the fair value approximated its cost and redemption value and therefore no amount was recognized in OCI.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2015, the Company's long-term debt had a carrying value of $3,683 million (2014 - $3,127 million) and a fair value of $4,159 million (2014 - $3,709 million).

The fair value of other financial assets and liabilities other than derivative instruments approximates their cost due to the short period to maturity.

17. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Earnings before income taxes	**245**	252	260
Federal statutory income tax rate	**15.0%**	15.0%	15.0%
Federal income taxes at statutory rate	**37**	38	39
Increase/(decrease) resulting from:			
Provincial and state income taxes	**5**	3	19
Effects of rate regulated accounting[1]	**(22)**	(25)	(5)
Non-taxable intercompany distributions	**(9)**	(9)	(9)
Other[2]	**-**	(1)	(1)
Income taxes	**11**	6	43
Effective income tax rate	**4.5%**	2.4%	16.5%

1 During 2015 and 2014, previously collected costs for future removal and site restoration were refunded to customers that resulted in a decrease in income taxes of $24 million at December 31, 2015 (2014 - $26 million).

2 Included in "Other" are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals & entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**243**	249	258
United States	**2**	3	2
	245	252	260
Current income taxes			
Canada	**(4)**	2	51
United States	**(1)**	1	1
	(5)	3	52
Deferred income taxes			
Canada	**14**	3	(9)
United States	**2**	-	-
	16	3	(9)
Income taxes	**11**	6	43

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2015**	2014
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(600)**	(577)
Financial derivatives	**-**	(3)
Regulatory assets	**(86)**	(72)
Other	**(1)**	(1)
Total deferred income tax liabilities	**(687)**	(653)
Deferred income tax assets		
Future removal and site restoration reserves	**146**	143
Deferrals	**-**	53
Retirement and postretirement benefits	**30**	21
Minimum tax credits	**9**	-
Financial derivatives	**2**	-
Other	**2**	4
Total deferred income tax assets	**189**	221
Net deferred income tax liabilities	**(498)**	(432)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 5)*	**18**	23
Deferred amounts and other assets *(Note 7)*	**8**	8
Total deferred income tax assets	**26**	31
Liabilities		
Deferred income taxes	**(524)**	(463)
Total deferred income tax liabilities	**(524)**	(463)
Net deferred income tax liabilities	**(498)**	(432)

The Company has assessed all tax positions. As a result, no significant adjustments were required to be made to the income tax provisions for the year ended December 31, 2015.

The Company has not provided for deferred income taxes on the difference between the carrying value of its foreign subsidiaries and their corresponding tax bases as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying value of the investment and its tax basis is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries is $30 million (2014 - $21 million). If such earnings were remitted, in the form of dividends or otherwise, the Company may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

The Company and its subsidiaries are subject to taxation in Canada and the Unites States. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario). The Company's 2011 to 2014 taxation years are still open for audit in Canada.

18. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

The Company maintains a non-contributory basic pension plan that provides either defined benefit or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees.

A measurement date of December 31, 2015 was used to determine the plan assets and accrued benefit obligation for the pension plans.

Defined Benefit Plans
Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation-indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective date of the most recent actuarial valuation was December 31, 2013. The effective date of the next required actuarial valuation is December 31, 2016.

Defined Contribution Plans
Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

OTHER POSTRETIREMENT BENEFITS
The Company also provides OPEB, which primarily includes supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS
The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension		OPEB	
December 31,	**2015**	2014	**2015**	2014
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,046**	875	**117**	100
Service cost	**35**	25	**1**	2
Interest cost	**41**	43	**5**	6
Actuarial loss/(gain)	**(54)**	142	**(1)**	12
Benefits paid	**(43)**	(41)	**(4)**	(3)
Other	**-**	2	**2**	-
Benefit obligation at end of year	**1,025**	1,046	**120**	117
Change in plan assets				
Fair value of plan assets at beginning of year	**960**	866	**13**	9
Actual return on plan assets	**49**	96	**-**	2
Employer's contributions	**3**	41	**5**	5
Benefits paid	**(43)**	(41)	**(4)**	(3)
Other	**-**	(2)	**3**	-
Fair value of plan assets at end of year	**969**	960	**17**	13
Underfunded status at end of year	**(56)**	(86)	**(103)**	(104)
Presented as follows:				
Deferred amounts and other assets *(Note 7)*	**6**	4	**2**	-
Accounts payable and other *(Note 9)*	**-**	-	**(4)**	(4)
Other long-term liabilities *(Note 11)*	**(62)**	(90)	**(101)**	(100)

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2015**	2014	2013	**2015**	2014	2013
Discount rate	**4.2%**	4.0%	5.0%	**4.2%**	4.0%	5.0%
Average rate of salary increases	**3.4%**	3.7%	3.5%	**3.4%**	3.7%	3.5%

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2015**	2014	2013	**2015**	2014	2013
(millions of Canadian dollars)						
Benefits earned during the year	**35**	25	25	**1**	1	1
Interest cost on projected benefit obligations	**41**	43	38	**5**	6	4
Expected return on plan assets	**(62)**	(59)	(52)	**(1)**	(1)	(1)
Amortization of prior service costs	**-**	-	1	**-**	-	-
Amortization of actuarial loss	**19**	16	28	**1**	-	2
Net defined benefit costs on an accrual basis	**33**	25	40	**6**	6	6
Defined contribution benefit costs	**1**	1	1	**-**	-	-
Net benefit cost recognized on an accrual basis	**34**	26	41	**6**	6	6
Net amount recognized in OCI						
Net actuarial (gain)/loss[1]	**-**	-	-	**-**	9	(14)
Total amount recognized in OCI	**-**	-	-	**-**	9	(14)
Total net benefit cost on an accrual basis and amount recognized in OCI	**34**	26	41	**6**	15	(8)

1 *Unamortized actuarial losses included in AOCI, before tax, were $9 million relating to OPEB at December 31, 2015 (2014 - $9 million, 2013 - nil).*

The Company estimates that approximately $13 million related to pension plans and OPEB at December 31, 2015 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Actuarial loss	**13**	**-**	**13**
	13	**-**	**13**

Pension and OPEB costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension and OPEB costs due to the regulatory mechanism in place. As a result, the net pension and OPEB expense primarily consists of OEB approved pension and OPEB costs.

Regulatory adjustments were recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers, respectively, in future rates *(Note 4)*. For the year ended December 31, 2015, an offsetting regulatory asset of nil (2014 - regulatory liability of $6 million) has been recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2015**	2014	2013	**2015**	2014	2013
Discount rate	**4.0%**	5.0%	4.3%	**4.0%**	5.0%	4.3%
Average rate of return on pension plan assets	**6.8%**	6.8%	6.8%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.7%**	3.5%	3.5%	**3.7%**	3.5%	3.5%

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in Which Ultimate Medical Cost Trend Rate Assumption is Achieved
Drugs	7.7%	4.3%	2029
Other medical and dental	4.5%	4.5%	-

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $12 million in the benefit obligation and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $10 million in the benefit obligation and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2015**	2014	**2015**	2014
Expected rate of return	**6.8%**	6.8%	**-**	-

Target Mix for Plan Assets

Equity securities	44.5%
Fixed income securities	40.0%
Other	15.5%

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2015, the pension assets were invested in 47% (2014 - 55%) in equity securities, 36% (2014 - 36%) in fixed income securities and 17% (2014 - 9%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $29 million (2014 - $18 million) have been excluded from the table below.

	2015				2014			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension Benefits								
Cash and cash equivalents	**10**	**-**	**-**	**10**	14	-	-	14
Fixed income securities								
Canadian government real return bonds	**73**	**-**	**-**	**73**	71	-	-	71
Canadian corporate bond index fund	**133**	**-**	**-**	**133**	137	-	-	137
Canadian government bond index fund	**128**	**-**	**-**	**128**	131	-	-	131
Corporate bonds and debentures	**4**	**-**	**-**	**4**	4	-	-	4
United States debt index fund	**2**	**-**	**-**	**2**	2	-	-	2
Equity								
Canadian equity securities	**71**	**-**	**-**	**71**	71	-	-	71
Canadian equity funds	**128**	**-**	**-**	**128**	137	-	-	137
United States equity securities	**1**	**-**	**-**	**1**	1	-	-	1
United States equity funds	**100**	**-**	**-**	**100**	77	19	-	96
Global equity funds	**71**	**79**	**-**	**150**	149	63	-	212
Infrastructure[4]	**-**	**-**	**96**	**96**	-	-	30	30
Real estate[5]	**-**	**-**	**51**	**51**	-	-	39	39
Forward currency contracts	**-**	**(7)**	**-**	**(7)**	-	(3)	-	(3)
	721	**72**	**147**	**940**	794	79	69	942
OPEB								
Cash and cash equivalents	**1**	**-**	**-**	**1**	1	-	-	1
Fixed income securities								
United States government and government agency bonds	**6**	**-**	**-**	**6**	5	-	-	5
Equity								
United States equity fund	**5**	**-**	**-**	**5**	4	-	-	4
Global equity fund	**5**	**-**	**-**	**5**	3	-	-	3
	17	**-**	**-**	**17**	13	-	-	13

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair value of the investment in United States Limited Partnership - Global Infrastructure Fund and IFM Global Infrastructure (Canada) L.P. are established through the use of valuation models.
5 The fair value of the investment in Bentall Kennedy Prime Canadian Property Fund Ltd and MetLife Core Property Fund L.P. are established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Balance at beginning of year	**69**	67
Unrealized and realized gains	**26**	15
Purchases and settlements, net	**52**	(13)
Balance at end of year	**147**	69

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension		OPEB	
Year ended December 31,	**2015**	2014	**2015**	2014
(millions of Canadian dollars)				
Total contributions	**4**	41	**5**	5

The contributions expected to be paid in 2016 for pension is $4 million and for OPEB is $4 million.

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2016	2017	2018	2019	2020	2021-2025
(millions of Canadian dollars)						
Expected future benefit payments	48	50	52	54	56	310

19. SEVERANCE COSTS

Included in Operating and administrative expense is $12 million in severance costs related to one-time termination benefits to employees. This resulted from an Enbridge-wide reduction of workforce that occurred in November 2015 that affected approximately 5% of Enbridge's workforce.

In 2015, $4 million was paid with the remaining $8 million to be paid in 2016 and is included in Accounts payable and other as at December 31, 2015.

20. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Regulatory assets	**532**	(732)	(31)
Regulatory liabilities[1]	**(178)**	(102)	2
Accounts receivable and other[2,3]	**34**	24	(13)
Gas inventories	**17**	(181)	(41)
Deferred amounts and other assets[2]	**-**	(3)	(2)
Accounts payable and other[2,3]	**(84)**	(92)	80
Other long-term liabilities[2]	**4**	55	(81)
	325	(1,031)	(86)

1 *Excludes the refund of revenues paid to customers in January 2015.*
2 *The cash flow impacts of regulatory assets and liabilities have been separately disclosed and are not included.*
3 *Includes amounts related to affiliated companies.*

21. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Enbridge Energy Distribution Inc.			
Common share dividends declared	**223**	204	200
IPL System Inc. *(Note 16)*			
Dividend income	**63**	63	63
Interest expense *(Note 10)*	**27**	27	27
Enbridge			
Purchase of treasury and other management services	**50**	41	38
Interest expense *(Note 10)*	**-**	2	-
Tidal Energy Marketing Inc.			
Purchase of natural gas	**23**	41	30
Revenue from optimization services	**7**	7	4
Tidal Energy Marketing (U.S.) LLC			
Purchase of natural gas	**24**	57	21
Aux Sable Canada LP			
Purchase of natural gas	**62**	16	-
Gazifère Inc.			
Revenue from wholesale service, including gas sales	**40**	31	30
Vector Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**28**	27	24
Vector Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**2**	2	2
Alliance Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**28**	26	26
Alliance Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**22**	20	19
Niagara Gas Transmission Limited			
Purchase of gas transportation services	**2**	2	2

The Company had related party balances as follows:

December 31,	**2015**	2014
(millions of Canadian dollars)		
Common share ownership from parent company		
Enbridge Energy Distribution Inc.	**1,637**	1,437
Dividend payable	**56**	51
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**2**	2
Note payable to affiliate company		
Enbridge (U.S.)	**40**	29
Credit facility to affiliate company		
Enbridge	**-**	175
Other accounts receivable/(payable)		
Gazifère Inc.	**3**	6
Enbridge Employee Services Inc.	**(13)**	-
Enbridge	**(4)**	(7)
Tidal Energy Marketing (U.S.) LLC	**(4)**	(3)
Alliance Pipeline Limited Partnership (Canadian)	**(2)**	(2)
Aux Sable Canada LP	**(2)**	(8)
Alliance Pipeline Limited Partnership (U.S.)	**(2)**	(2)
Vector Pipeline Limited Partnership (U.S.)	**(1)**	(2)
Enbridge Pipelines Inc.	**-**	(15)
Tidal Energy Marketing Inc.	**-**	(3)
Other accounts receivable	**2**	-
Other accounts payable	**(1)**	-

Financing Transactions

The Company has invested in Class D, non-voting, redeemable, retractable preference shares of IPL System Inc., an affiliate under common control. At December 31, 2015, the investment of $825 million (2014 - $825 million) in these shares resulted in a weighted average dividend yield of 7.60%.

At December 31, 2015, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.50%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preference shares of the Company. For the year ended December 31, 2015, interest paid amounted to $27 million (2014 - $27 million).

The Company has a $300 million revolving credit facility with Enbridge with a maturity date in May 2017. At December 31, 2015, the total drawings on the revolving credit facility were nil (2014 - $175 million). For the year ended December 31, 2015, interest paid amounted to nil (2014 - $2 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 0.55% and is payable on demand.

Treasury and Other Management Services

Enbridge provides treasury and other management services and charges the Company on a cost recovery basis.

Natural Gas Purchases
The Company has contracted for the purchase of natural gas from Aux Sable Canada LP, Tidal Energy Marketing Inc. and Tidal Energy Marketing (U.S.) LLC, related entities under common control, at prevailing market prices and under normal trade terms. Contractual obligations under these contracts are nil.

Wholesale Service
These gas procurement and transportation services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Transportation Services
The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control, and Niagara Gas Transmission Limited. Contractual obligations under these contracts are 2016 to 2017 - $71 million, 2018 to 2019 - $20 million and thereafter - nil.

Trade Receivables and Payables
The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other shared corporate services to affiliates on a fully-allocated cost basis. Market prices, if they are reasonably determinable, are charged for affiliate services that are not shared corporate services. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

Other Transactions
The Company and affiliates invoice on a monthly basis and amounts are due and paid on a monthly basis.

22. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $5,722 million. The amounts which are expected to be paid in the next five years are $1,354 million, $942 million, $595 million, $566 million, and $487 million, respectively, and $1,778 million thereafter.

Minimum future payments under operating leases are estimated at $4 million in aggregate. Estimated annual lease payments for the years ended December 31, 2016 through 2020 are $4 million, nil, nil, nil and nil, respectively. Total rental expense for operating leases, classified in Operating and administrative expense, was $3 million for each of the years ended December 31, 2015, 2014 and 2013.

The Company, Enbridge, and Enbridge Pipeline Inc., in aggregate, have access to $95 million of letters of credit that they can issue, of which $37 million was unutilized as of December 31, 2015. The total outstanding letters of credit that related to the Company as of December 31, 2015 was $5 million. The Company had access to $75 million of letters of credit that it could issue, of which $51 million was unutilized as of December 31, 2014. The total outstanding letters of credit that related to the Company as of December 31, 2014 was $24 million.

CONTINGENCIES

Former Manufactured Coal Gas Plant Sites
The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were

commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, a former owner of part of the Historic Distillery District (Wyndham Court Canada Inc.) commenced an action in the Ontario Court of Justice (General Division) against the Company alleging that coal tar originating from the Company's Station A MGP in Toronto had migrated to its lands. The Company entered into a Tolling Agreement with Wyndham Court Canada Inc. pursuant to which this action was discontinued, without prejudice to the right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham Court Canada Inc. sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape).

Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but the required steps in the discovery process were not completed by the plaintiff. The Company has brought a motion to dismiss the plaintiff's action for delay. At present, it is unknown when or if the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2015 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

OTHER LITIGATON

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a significant impact on the Company's consolidated financial position or results of operations.

ENBRIDGE GAS DISTRIBUTION INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2016

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Gas Distribution Inc.

Financial Reporting
Management of Enbridge Gas Distribution Inc. (the Company) is responsible for the accompanying consolidated financial statements and all related financial information, including Management’s Discussion and Analysis. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, includes directors who are unrelated and independent, and has a specific responsibility to oversee management’s efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company’s internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with U.S. GAAP and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

(Signed)

Cynthia L. Hansen
President

(Signed)

William M. Ramos
Vice President, Finance

February 16, 2017

February 16, 2017

Independent Auditor's Report

To the Shareholders of
Enbridge Gas Distribution Inc.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2016 and December 31, 2015 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2016, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215, www.pwc.com/ca

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and their subsidiaries as at December 31, 2016 and December 31, 2015 and its results of operations and their cash flows for each of the three years in the period ended December 31, 2016 in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Revenues			
Gas commodity and distribution revenue *(Note 22)*	**2,437**	3,043	2,803
Transportation of gas for customers	**330**	344	305
Other revenue *(Note 22)*	**100**	97	92
	2,867	3,484	3,200
Expenses			
Gas commodity and distribution costs *(Note 22)*	**1,636**	2,322	2,046
Operating and administrative *(Notes 15, 20 and 22)*	**534**	509	493
Depreciation and amortization *(Notes 7 and 9)*	**322**	290	286
Earnings sharing *(Note 4)*	**3**	7	12
	2,495	3,128	2,837
	372	356	363
Other income *(Note 22)*	**73**	70	66
Interest expense, net *(Notes 11, 17 and 22)*	**(206)**	(181)	(177)
	239	245	252
Income taxes expense *(Note 18)*	**(9)**	(11)	(6)
Earnings	**230**	234	246
Preference share dividends *(Note 14)*	**(2)**	(2)	(2)
Earnings attributable to the common shareholder	**228**	232	244

The accompanying notes are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Earnings	**230**	234	246
Other comprehensive loss, net of tax *(Notes 16 and 17)*			
Change in unrealized loss on cash flow hedges	**(11)**	(18)	(62)
Reclassification to earnings of realized loss on cash flow hedges	**5**	5	-
Actuarial gain/(loss) on other postretirement benefits (OPEB) (*Note 19)*	**(1)**	-	(7)
Change in foreign currency translation adjustment	**(2)**	8	3
Other comprehensive loss	**(9)**	(5)	(66)
Comprehensive income	**221**	229	180
Preference share dividends	**(2)**	(2)	(2)
Comprehensive income attributable to the common shareholder	**219**	227	178

The accompanying notes are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Preference shares *(Note 14)*	**100**	100	100
Common shares *(Note 14)*			
Balance at beginning of year	**1,637**	1,437	1,287
Common shares issued	**280**	200	150
Balance at end of year	**1,917**	1,637	1,437
Additional paid-in capital	**1,148**	1,148	1,148
Retained earnings			
Balance at beginning of year	**71**	62	22
Earnings attributable to the common shareholder	**228**	232	244
Common share dividends declared *(Note 22)*	**(237)**	(223)	(204)
Balance at end of year	**62**	71	62
Accumulated other comprehensive loss *(Note 16)*			
Balance at beginning of year	**(6)**	(1)	65
Other comprehensive loss	**(9)**	(5)	(66)
Balance at end of year	**(15)**	(6)	(1)
Total shareholders' equity	**3,212**	2,950	2,746

The accompanying notes are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Operating activities			
Earnings	**230**	234	246
Depreciation and amortization *(Notes 7 and 9)*	**322**	290	286
Deferred income taxes *(Note 18)*	**(22)**	16	4
Refund of revenues	**-**	(52)	52
Non-cash net defined pension and OPEB obligation costs	**30**	31	(5)
Other	**4**	(2)	18
Changes in operating assets and liabilities *(Notes 5 and 21)*	**78**	325	(1,031)
	642	842	(430)
Investing activities			
Additions to property, plant and equipment	**(545)**	(977)	(601)
Additions to intangible assets	**(57)**	(46)	(36)
Change in construction payable	**(138)**	151	17
Proceeds from disposition	**-**	8	-
	(740)	(864)	(620)
Financing activities			
Change in bank indebtedness	**45**	18	9
Net change in short-term borrowings *(Note 11)*	**(248)**	(340)	564
Net change in short-term borrowings from affiliates *(Note 22)*	**(6)**	(170)	189
Term note and credit facility issuances *(Note 11)*	**309**	558	729
Term credit facility repayments	**(7)**	(2)	(400)
Common shares issued *(Notes 14 and 22)*	**280**	200	150
Preference share dividends	**(2)**	(2)	(2)
Common share dividends	**(233)**	(218)	(203)
Other	**-**	(3)	(2)
	138	41	1,034
Increase/(decrease) in cash and cash equivalents	**40**	19	(16)
Cash and cash equivalents at beginning of year	**36**	17	33
Cash and cash equivalents at end of year	**76**	36	17
Supplementary cash flow information			
Income taxes paid/(received)	**5**	(17)	23
Interest paid *(Note 11)*	**208**	193	191

The accompanying notes are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2016**	2015
(millions of Canadian dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**76**	36
Restricted cash *(Note 5)*	**58**	-
Accounts receivable and other *(Notes 3, 4, 6, 17 and 18)*	**655**	790
Due from affiliates *(Note 22)*	**16**	10
Gas inventories	**512**	547
	1,317	1,383
Property, plant and equipment, net *(Note 7)*	**7,418**	7,081
Investment in affiliate *(Notes 17 and 22)*	**825**	825
Deferred amounts and other assets *(Notes 3, 4, 8, 18 and 19)*	**576**	543
Intangible assets, net *(Note 9)*	**158**	157
	10,294	9,989
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**72**	27
Short-term borrowings *(Note 11)*	**351**	599
Short-term borrowings from affiliate *(Notes 11 and 22)*	**34**	40
Accounts payable and other *(Notes 4, 5, 10, 17, 19 and 20)*	**807**	870
Due to affiliates *(Note 22)*	**95**	87
Current maturities of long-term debt *(Note 11)*	**500**	2
	1,859	1,625
Long-term debt *(Notes 3 and 11)*	**3,470**	3,668
Other long-term liabilities *(Notes 4, 12, 13, 17 and 19)*	**846**	847
Deferred income taxes *(Notes 3 and 18)*	**532**	524
Loans from affiliate *(Notes 11 and 22)*	**375**	375
	7,082	7,039
Shareholders' equity		
Share capital *(Note 14)*		
Preference shares *(convertible; 4 outstanding at December 31, 2016 and December 31, 2015)*	**100**	100
Common shares *(186 and 170 outstanding at December 31, 2016 and 2015, respectively)*	**1,917**	1,637
Additional paid-in capital	**1,148**	1,148
Retained earnings	**62**	71
Accumulated other comprehensive loss *(Note 16)*	**(15)**	(6)
	3,212	2,950
	10,294	9,989

The accompanying notes are an integral part of these Consolidated Financial Statements.

Approved by the Board of Directors:

(Signed)

Cynthia L. Hansen
President

(Signed)

J. Herb England
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These Consolidated Financial Statements are prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company is permitted to prepare its Consolidated Financial Statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under an exemption granted by securities regulators in Canada until 2018.

BASIS OF PRESENTATION AND USE OF ESTIMATES
The preparation of Consolidated Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the Consolidated Financial Statements. Significant estimates and assumptions used in the preparation of the Consolidated Financial Statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 4)*; unbilled revenues *(Note 6)* and unbilled amounts pertaining to the Budget Billing Program *(Note 10)*; allowance for doubtful accounts *(Note 6)*; carrying value of gas inventory; depreciation rates and carrying value of property, plant and equipment *(Note 7)*; amortization rates and carrying value of intangible assets *(Note 9)*; valuation of stock-based compensation *(Note 15)*; fair value of financial instruments *(Note 17)*; provisions for income taxes *(Note 18)*; assumptions used to measure retirement and OPEB *(Note 19);* commitments and contingencies *(Note 23)*; and fair value of asset retirement obligations (ARO) *(Note 13)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION
The Consolidated Financial Statements include the accounts of the Company and its subsidiary. All significant intercompany accounts and transactions are eliminated upon consolidation.

REGULATION
The utility operations of the Company, excluding St. Lawrence, are regulated by the Ontario Energy Board (OEB) and the utility operations of St. Lawrence are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities *(Note 4)*.

REVENUE RECOGNITION
The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company’s franchise areas.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

PUSH-DOWN ACCOUNTING

The Company elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted U.S. GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by the Company. Upon adopting push-down accounting, the historical cost of the Company's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in interest rates and foreign exchange. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges at December 31, 2016 or 2015.

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in currency exchange rates related to unregulated storage revenue and changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/loss (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

The Company recognizes the fair value of derivative instruments on the Consolidated Statements of Financial Position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs as a direct deduction from the carrying amount of the related debt liability. These costs are amortized using the effective interest rate method over the life of the related debt instrument and are recorded in Interest expense.

INCOME TAXES
The liability method of accounting for income taxes is followed. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in income taxes. Deferred tax liabilities and assets are classified as noncurrent in the Consolidated Statements of Financial Position.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as approved by the Regulators for rate-making purposes. As a result, rates do not include the recovery of deferred income taxes related to temporary differences. A corresponding deferred income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates (*Note 4*).

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Consolidated Statement of Financial Position. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar (USD). The effects of translating the financial statements of St. Lawrence to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI). Asset and liability accounts are translated at the exchange rates in effect on the date of the Consolidated Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

RESTRICTED CASH
Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific agreements, are presented as Restricted cash on the Consolidated Statements of Financial Position *(Note 5)*.

GAS INVENTORIES
Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction as authorized by the Regulators. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the Regulators. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation until the last asset in the pool is disposed of. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily include: costs which the Regulators have permitted, or are expected to permit, to be recovered through future rates; deferred income taxes; and derivative financial instruments.

INTANGIBLE ASSETS
Intangible assets consist primarily of the Company's Customer Information System (CIS) and software costs, including the Work and Asset Management Solution (WAMS). The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS
The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality.

Effective January 1, 2016, the Company refined the method to estimate current service cost and interest cost for pension and other postretirement benefits. Previously, these were estimated utilizing a single weighted-average discount rate derived from the yield curve used to measure the defined benefit obligation at the beginning of the year. Under the refined method, different discount rates are derived from the same yield curve, reflecting the different timing of benefit payments for past service (the defined benefit obligation) and future service (the current service cost). Differentiating in this way represents a refinement in the basis of estimation applied in prior periods. This change does not affect the measurement of the total defined benefit obligation recorded on the Consolidated Statements of Financial Position as at December 31, 2016 or any other period. The refinement compared to the previous method resulted in a decrease in the current service cost and interest components with an equal offset to actuarial gains (losses) with no net impact on the total benefit obligation. The refinement did not have a material impact on the Consolidated Statements of Earnings for the year ended December 31, 2016. This change was accounted for prospectively as a change in accounting estimate.

In 2014, new mortality assumptions were issued and further revised in 2015. These assumptions were adopted by the Company for the measurement of the December 31, 2015 benefit obligations. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contributions occur.

The Company also provides OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities, respectively, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

The Company records regulatory adjustments to reflect the difference between pension expense and OPEB costs for accounting purposes and the pension expense and OPEB costs for rate-making purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension expense or OPEB costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation accounting, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION

Enbridge grants stock-based compensation to certain employees and senior officers of the Company through four long-term incentive compensation plans. Compensation expense associated with each of the plans, as determined under the methods outlined below is recognized in Operating and administrative expense. Amounts owing to Enbridge in respect of stock-based compensation are payable on a quarterly basis.

Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISOs granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of the Company's shares. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

Performance Stock Options (PSO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the PSOs granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period. The options become exercisable when both performance targets and the time vesting requirements have been met.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or a liability has been incurred, and the amount of the impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Classification of Deferred Taxes on the Statement of Financial Position

Effective January 1, 2016, the Company elected to early adopt Accounting Standards Update (ASU) 2015-17 and applied the standard on a prospective basis. The amendments require that deferred tax liabilities and assets be classified as noncurrent in the Consolidated Statements of Financial Position. The adoption of the standard resulted in a decrease to Deferred income taxes of $18 million and a decrease to Accounts receivable and other of $18 million.

Measurement Date of Defined Benefit Obligation and Plan Assets

Effective January 1, 2016, the Company adopted ASU 2015-04 on a prospective basis. The revised criteria simplifies the fair value measurement of defined benefit plan assets and obligations. The adoption of the pronouncement did not have a material impact on the Company's Consolidated Financial Statements.

Simplifying the Presentation of Debt Issuance Costs

Effective January 1, 2016, the Company adopted ASU 2015-03 on a retrospective basis which, as at December 31, 2015, resulted in a decrease in Deferred amounts and other assets of $13 million and a corresponding decrease in Long-term debt of $13 million. The new standard requires debt issuance costs related to a recognized debt liability to be presented in the Consolidated Statements of Financial Position as a direct deduction from the carrying amount of that debt liability, consistent with the presentation of debt discounts or premiums. Further, effective January 1, 2016, the Company adopted ASU 2015-15 which clarifies that debt issuance costs associated with line-of-credit arrangements may be deferred as an asset and subsequently amortized over the term of the arrangement. The adoption of ASU 2015-15 did not have a material impact on the Company's Consolidated Financial Statements.

FUTURE ACCOUNTING POLICY CHANGES

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows

ASU 2016-18 was issued in November 2016 with the intent to add or clarify the guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the cash flow statement. The amendments require that changes in restricted cash and restricted cash equivalents should be included within cash and cash equivalents when reconciling the opening and closing period amounts shown on the Statements of Cash Flows. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements. The accounting update is effective for fiscal years beginning after December 15, 2017 and is to be applied on a retrospective basis.

Simplifying Cash Flow Classification
ASU 2016-15 was issued in August 2016 with the intent of reducing diversity in practice of how certain cash receipts and cash payments are classified in the Consolidated Statements of Cash Flows. The new guidance addresses eight specific presentation issues. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2017 and is to be applied on a retrospective basis.

Accounting for Credit Losses
ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses, which delays the recognition until it is probable a loss has been incurred. The amendment adds a new impairment model, known as the current expected credit loss model that is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2019.

Improvements to Employee Share-Based Payment Accounting
ASU 2016-09 was issued in March 2016 with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the Consolidated Statements of Cash Flows. The accounting update is effective for annual and interim periods beginning on or after December 15, 2016 and is to be applied on a prospective or retrospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's Consolidated Financial Statements.

Recognition of Leases
ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the Statement of Financial Position and disclosing additional key information about leasing arrangements. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements. The accounting update is effective for interim and annual periods beginning on or after December 15, 2018, and is to be applied using a modified retrospective approach.

Recognition and Measurement of Financial Assets and Liabilities
ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation, and disclosure of financial assets and liabilities. The amendments revise accounting related to the classification and measurement of investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value, and the disclosure requirements associated with the fair value of financial instruments. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements. The accounting update is effective for fiscal years beginning after December 15, 2017, and is to be applied by means of a cumulative-effect adjustment to the Statements of Financial Position as of the beginning of the fiscal year of adoption, with amendments related to equity securities without readily determinable fair values to be applied prospectively.

Revenue from Contracts with Customers
ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. The standard is effective January 1, 2018. The new revenue standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a

modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. The Company is currently assessing which transition method to use.

The Company has reviewed a sample of its revenue contracts in order to evaluate the effect of the new standard on its revenue recognition practices. Based on our initial assessment, the application of the standard may result in a change in presentation related to payments to customers under the earnings sharing mechanism which are currently shown as an expense in the Consolidated Statements of Earnings. Under the new standard, these payments would be reflected as a reduction of revenue. While we have not yet completed our assessment, our preliminary view is that we do not expect these changes to have a material impact on our revenue or earnings. The Company is also developing processes to generate the disclosures required under the new standard.

4. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

For the purposes of this note, “Enbridge Gas Distribution” refers specifically to Enbridge Gas Distribution Inc. excluding St. Lawrence, whereas “St. Lawrence” refers specifically to St. Lawrence Gas Company, Inc.

RECENT RATE APPROVALS

Enbridge Gas Distribution
For the year ended December 31, 2016, Enbridge Gas Distribution’s rates were set according to the OEB approved settlement agreement (December 2015) in the Company’s 2016 rate application, updated to reflect the OEB’s decision and final rate order (May 2016) in the Company’s multi-year demand side management (DSM) application. The rates approved as part of the 2016 rate application represented the third year of the Company’s customized incentive regulation (IR) plan, which set rates for the period of 2014 to 2018, and was approved by the OEB in July and August 2014. As specified within the customized IR plan, DSM costs are one of the select items to be updated annually.

For the year ended December 31, 2015, Enbridge Gas Distribution’s rates were set according to the OEB approved settlement agreement (April 2015) and final rate order (May 2015), in the Company’s 2015 rate application.

For the year ended December 31, 2014, Enbridge Gas Distribution’s rates were set by the OEB’s July 2014 decision, and subsequent August 2014 decision and rate order in the Company’s customized IR application. The decisions and rate order established final 2014 allowed revenues and billing rates, as well as placeholder allowed revenues for 2015 through 2018. The customized IR plan requires Enbridge Gas Distribution to update select items in each of 2015 through 2018, in order to establish final allowed revenues and rates. The customized IR decision also approved the adoption of a new approach for determining net negative salvage percentages as a component of Enbridge Gas Distribution’s depreciation rates, as well as an earnings sharing mechanism in which Enbridge Gas Distribution shares earnings above the approved base return equally with customers.

Under the customized IR plan, the Company has continued to apply the accounting guidance found in Accounting Standards Codification (ASC) 980 – Regulated Operations.

St. Lawrence
St. Lawrence is currently in a rate year ending May 31, 2017, according to the recent NYSPSC order establishing a three year rate plan covering the period of June 1, 2016 through May 31, 2019. For the years ended December 31, 2016, 2015 and 2014, St. Lawrence’s rates were set using a Cost of Service (COS) methodology. Under COS, revenues are set to recover costs and to earn a rate of return on the deemed common equity component of rate base. Costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, interest and income taxes. Rate base is the average level of investment in all recoverable assets used in natural gas distribution,

storage and transmission and an allowance for working capital. Gas costs are not recovered through revenue rates, but are set separately in gas cost rates.

For the rate year ending May 31, 2017, any earnings above the approved return on equity and between 9.5% to 10.0% will be shared 50/50 between customers and the Company; from 10.0% to 10.5%, 80/20; and over 10.5%, 90/10; respectively. The calculation of earnings is on an annual basis for each rate year period commencing June 1, 2016. There was no earnings sharing for the period of January 1, 2016 to May 31, 2016. In fiscal 2015 and fiscal 2014, any earnings above a return on equity of 11% were shared equally with the customers. The calculation from January 1, 2015 to December 31, 2015 resulted in no sharing impact as at December 31, 2015 (2014 – nil).

Under COS, it is the responsibility of St. Lawrence to demonstrate to the NYSPSC the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken.

During the years ended December 31, 2016, 2015 and 2014, the cost of natural gas was passed on to customers as a flow-through.

APPROVED RETURNS ON EQUITY

Enbridge Gas Distribution

Enbridge Gas Distribution’s rates for 2016 included an after-tax rate of return on common equity of 9.19% (2015 - 9.30% and 2014 - 9.36%) based on a 36% (2015 and 2014 - 36%) deemed common equity component of rate base.

St. Lawrence

St. Lawrence’s approved after-tax rate of return on common equity embedded in rates was 9.0% for the rate year ended May 31, 2017 (fiscal 2015 and fiscal 2014 - 10.5%) based on a 48% (fiscal 2015 and fiscal 2014 - 50%) deemed common equity component of rate base.

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities

As a result of rate regulation accounting, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation accounting, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. The Regulators’ future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators’ future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

FINANCIAL STATEMENT EFFECTS

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	**2016**	2015	Consolidated Statement of Financial Position Location**	Estimated Recovery/ Settlement Period *(years)*
(millions of Canadian dollars)				
Regulatory assets/(liabilities)				
Enbridge Gas Distribution				
Deferred income taxes[1]	**381**	324	DA	*
OPEB[2]	**71**	75	AR/DA	16
Pension plans, net[3]	**55**	30	DA/OLTL	*
Constant dollar net salvage adjustment[4]	**38**	42	DA	*
Unaccounted for gas variance[5]	**13**	3	AR	1
Average use true-up variance[6]	**10**	(2)	AR/OLTL	*
Storage and transportation deferral[7]	**10**	5	AR	1
Customer care CIS rate smoothing deferral[8]	**8**	9	DA/OLTL	2
Deferred rebate deferral[9]	**8**	-	AR	1
Demand side management incentive[10]	**6**	8	AR	*
Purchased gas variance[11]	**5**	129	AR	1
GTA incremental transmission capital revenue requirement deferral[12]	**4**	-	AR	1
Unabsorbed demand cost[13]	**-**	66	AR	*
Future removal and site restoration reserves[14]	**(577)**	(553)	OLTL	*
Site restoration clearance adjustment[15]	**(109)**	(193)	AP/OLTL	2
Post-retirement true-up variance[16]	**(10)**	(1)	AP/OLTL	*
Transactional services deferral[17]	**(4)**	(9)	AP	1
Earnings sharing deferral[18]	**(3)**	(6)	AP	*
Other regulatory assets and liabilities, net	**1**	3	***	***
	(93)	(70)		
St. Lawrence				
Other regulatory assets and liabilities, net	**7**	6	***	***
	(86)	(64)		

* Refer to the footnote for details

** AR – Accounts receivable and other
AP – Accounts payable and other
DA – Deferred amounts and other assets
OLTL – Other long-term liabilities

*** Dependent on the nature of the item

1 *The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate regulation accounting, this regulatory balance and the related earnings impact would not be recorded.*

2 *The OPEB balance represents Enbridge Gas Distribution's right to recover OPEB costs resulting from the adoption of the accrual basis of accounting for OPEB costs upon transition to US GAAP in 2012. Pursuant to the OEB rate order, the amount as at December 31, 2012 is to be collected in rates over a 20-year period that commenced in 2013. In the absence of rate regulation accounting, this regulatory balance and related earnings impact would not be recorded.*

3 *The pension plan balance represents the regulatory offset to the pension liability/asset to the extent the amounts are to be collected/refunded in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation accounting, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

4 *The Constant dollar net salvage adjustment represents the cumulative variance between the amount proposed for clearance and the actual amount cleared, relating specifically to the site restoration clearance adjustment. At the end of 2018 any residual balance will be cleared in a post 2018 true up, ensuring that the actual amount cleared is equivalent to the required $380 million.*

5 *Unaccounted for gas variance represents the difference between the total natural gas distributed by Enbridge Gas Distribution and the amount of natural gas billed or billable to customers for their recorded consumption, to the extent it is different from the approved amount built into rates. Enbridge Gas Distribution has historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation accounting, this variance would be included in earnings in the year incurred.*

6 *Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual weather normalized average use for general service customers. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation accounting, this regulatory balance and the related earnings impact would not be recorded.*

7 *Storage and transportation deferral represents the difference between the actual cost and the approved cost of natural gas storage and transportation reflected in rates. Enbridge Gas Distribution has historically been granted OEB approval to collect this balance from or to refund this balance to customers, generally in the subsequent year. In the absence of rate regulation accounting, the actual cost of natural gas storage and transportation would be included in Gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount, as the right to collect or refund the revenue or costs has been established.*

8 *Customer care CIS rate smoothing deferral represents the difference between the forecast costs and the approved costs for customer care and CIS reflected in rates. The balance accumulated during 2013 to 2015 when the cost per customer exceeded the cost approved for recovery in rates will be drawn down during 2016 to 2018 when the cost per customer will be lower than the cost approved for recovery in rates. Enbridge Gas Distribution has received OEB approval to collect from or refund to customers any remaining balance after 2018. In the absence of rate regulation accounting, the variance would be included in earnings in the year incurred.*

9 *The Deferred rebate account reflects amounts payable to, or receivable from, customers as a result of the clearing of deferral and variance accounts authorized by the OEB which remain outstanding due to the Company's inability to locate such customers. Enbridge Gas Distribution has historically been granted OEB approval to collect this balance from or to refund this balance to customers, generally in the subsequent year. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

10 *Demand side management incentive deferral account (DSMIDA) represents the benefit earned by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the DSMIDA amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

11 *Purchased gas variance (PGVA) is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. In the absence of rate regulation accounting, the actual cost of natural gas would be included in Gas commodity and distribution costs, and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established.*

12 *The GTA incremental transmission capital revenue requirement deferral account reflects the revenue requirement related to incremental capital costs which resulted from the upsizing of Segment A of the GTA project to a Nominal Pipe Size (NPS) 42 pipeline, from an NPS 36 pipeline. The account was required in the event that at the time Segment A was put into service, there are no transportation customers, or there is no ability for transportation customers to utilize Segment A. The revenue requirement reflects revenue to be collected from transportation customers once they are able to take service under Rate 332. In the absence of rate regulation accounting, the amount would be recognized when included in rates billed to transportation customers.*

13 *The Unabsorbed demand cost deferral account represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet requirements resulting from its Peak Gas Design Day Criteria. In the absence of rate regulation accounting, these costs would be expensed as incurred.*

14 *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment that is recorded in rates. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation accounting, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

15 *The Site restoration clearance adjustment represents the amount, that was determined by the OEB, of previously collected costs for future removal and site restoration that is now considered to be in excess of future requirements and will be refunded to customers over the customized IR term. This was a result of the OEB's approval of the adoption of a new approach for determining net negative salvage percentages. The new approach resulted in lower depreciation rates and lower future removal and site restoration reserves. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

16 *Post-retirement true-up variance is the difference between the actual cost and the approved cost of pension and OPEB reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers in the subsequent year, up to a maximum of $5 million per year. Any amounts in excess of $5 million per year will be deferred for refund or collection in the next subsequent year. In the absence of rate regulation accounting, the variance would be included in earnings in the year incurred.*

17 *Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

18 *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the customized IR plan. The Earnings sharing is payable to customers and represents 50% of normalized U.S. GAAP utility earnings represented by a return on equity in excess of the allowed utility return on equity applicable to Enbridge Gas Distribution, as determined for each year of the customized IR plan. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Revenue

To recognize the actions or expected actions of the Regulators, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

Operating Cost Capitalization

In the absence of rate regulation accounting, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred.

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation accounting, a portion of such operating costs would be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2016, cumulative costs relating to this services contract of $181 million (2015 - $174 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation accounting, some of these costs would be charged to earnings in the year incurred.

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2016, the net book value of these costs included in intangible assets was $35 million (2015 - $48 million). In the absence of rate regulation accounting, a portion of the original cost of these assets would have been expensed in the period incurred.

WAMS is the Company's new integrated work and asset management solution. At December 31, 2016, the net book value of the asset included in intangible assets was $84 million (2015 - $52 million was included in work-in-progress). In the absence of rate regulation accounting, a portion of the original cost of the asset would have been expensed in the period incurred.

Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. Included in gas inventories at December 31, 2016 is $49 million (2015 - $40 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation accounting, these costs would be expensed as incurred and inventory would be recorded at the lower of cost or market value.

Depreciation
In the absence of rate regulation accounting, depreciation rates would not have included a charge for future removal and site restoration costs.

5. GREEN INVESTMENT FUND

In July 2016, the Company received $58 million from the Government of Ontario for the purpose of carrying out the Green Investment Fund (GIF) program. The purpose of the GIF program is to reduce greenhouse gas emissions in the residential sector. The Company's use of the funds is limited to eligible expenditures for the purpose of executing the program. The Company will manage the GIF program separately from its core regulated activities. There is no earnings impact relating to the GIF program. Any unspent funds must be returned to the Government of Ontario at the expiry of the agreement on May 31, 2019, or should the Government of Ontario elect to terminate the agreement at any time prior to its expiration date.

As at December 31, 2016, the Company had Restricted cash of $58 million and Accounts payable and other *(Note 10)* of $57 million on the Consolidated Statements of Financial Position related to the funds received for the GIF program. The cash flow impacts of these items are included in Changes in operating assets and liabilities on the Consolidated Statements of Cash Flows (*Note 21*).

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2016**	2015
(millions of Canadian dollars)		
Trade receivables	**327**	309
Unbilled revenues	**135**	151
Regulatory assets *(Note 4)*	**66**	216
Rebillables receivable	**50**	40
Taxes receivable	**48**	19
Agent billing and collection receivable	**35**	39
Prepaid expenses	**11**	11
Current deferred income taxes *(Notes 3 and 18)*	**-**	18
Other	**16**	21
Allowance for doubtful accounts *(Note 17)*	**(33)**	(34)
	655	790

During the first half of 2014, increases in natural gas prices and colder than normal weather resulted in the Company accumulating a significant balance in its PGVA. In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. Included in Regulatory assets as at December 31, 2016 is $5 million (December 31, 2015 - $129 million) which represents the PGVA balance that is expected to be recovered from customers within the next 12 months.

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2016**	2015
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	**2.2%**	**4,637**	3,740
Gas services	**2.3%**	**3,065**	2,929
Regulating and metering equipment	**5.5%**	**963**	848
Gas storage	**1.9%**	**366**	327
Right-of-way	**1.2%**	**106**	52
Computer technology	**36.6%**	**33**	31
Under construction	**-**	**130**	893
Construction materials inventory	**-**	**34**	40
Land	**-**	**28**	24
Other	**6.7%**	**300**	303
		9,662	9,187
Accumulated depreciation		**(2,334)**	(2,197)
		7,328	6,990
Unregulated property, plant and equipment			
Gas storage	**2.0%**	**90**	88
Other	**0.5%**	**23**	27
		113	115
Accumulated depreciation		**(23)**	(24)
		90	91
Property, plant and equipment, net		**7,418**	7,081

Depreciation expense, including amounts collected for future removal and site restoration costs, was $266 million for the year ended December 31, 2016 (2015 - $239 million, 2014 - $237 million).

8. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2016**	2015
(millions of Canadian dollars)		
Regulatory assets *(Note 4)*	**568**	526
Pension and OPEB asset *(Note 19)*	**6**	8
Deferred income taxes *(Note 18)*	**-**	8
Other	**2**	1
	576	543

9. INTANGIBLE ASSETS

December 31, 2016	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**22.2%**	**279**	**(156)**	**123**
CIS	**10.0%**	**127**	**(92)**	**35**
		406	**(248)**	**158**

December 31, 2015	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	23.2%	238	(129)	109
CIS	10.0%	127	(79)	48
		365	(208)	157

Intangible assets include $12 million of work-in-progress as at December 31, 2016 (2015 - $61 million). Total amortization expense for intangible assets was $56 million for the year ended December 31, 2016 (2015 - $51 million, 2014 - $49 million). The Company expects aggregate amortization expense for the years ending December 31, 2017 through 2021 of $65 million, $70 million, $71 million, $64 million and $66 million, respectively.

10. ACCOUNTS PAYABLE AND OTHER

December 31,	2016	2015
(millions of Canadian dollars)		
Accrued liabilities *(Note 20)*	**371**	396
Regulatory liabilities *(Note 4)*	**96**	136
Trade payables	**82**	62
Budget billing plan payable	**75**	105
GIF liability *(Note 5)*	**57**	-
Security deposits	**51**	61
Interest payable	**36**	33
Taxes payable	**17**	9
Current portion of OPEB liability *(Note 19)*	**4**	4
Agent billing and collection payable	**3**	-
Contractual holdbacks	**3**	38
Dividends payable	**1**	1
Short-term portion of derivative liabilities *(Note 17)*	**1**	14
Other	**10**	11
	807	870

Included in Regulatory liabilities at December 31, 2016 is $78 million (2015 - $84 million) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers within the next 12 months.

11. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2016**	2015
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	85
Medium-term notes	4.38%	2017-2050	**3,895**	3,595
Commercial paper and credit facility draws, net[1]			**360**	607
Other *(Note 3)*[2]			**15**	22
Total debt			**4,355**	4,309
Current maturities			**(500)**	(2)
Short-term borrowings	0.85%		**(351)**	(599)
Short-term borrowings from affiliates *(Note 22)*	1.66%		**(34)**	(40)
Long-term debt *(Note 3)*			**3,470**	3,668
Loans from affiliate company *(Note 22)*			**375**	375

1 Includes amounts drawn on uncommitted demand credit facilities.
2 Consists of note payable to affiliate company, debt premium and debt issuance costs.

In August 2016, the Company issued $300 million of ten-year medium-term notes (MTNs) at an interest rate of 2.50%.

For the years ending December 31, 2017 through 2021, medium-term note maturities are $500 million, nil, $9 million, $400 million and $175 million, respectively. The Company's debentures and medium-term notes bear interest at fixed rates, and interest obligations for the years ending December 31, 2017 through 2021 are $176 million, $163 million, $163 million, $163 million and $147 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Debentures and medium-term notes	**176**	158	149
Loans from affiliate company *(Note 22)*	**27**	27	29
Commercial paper and credit facility draws	**7**	8	9
Other interest and finance costs	**10**	9	(4)
Capitalized	**(14)**	(21)	(6)
	206	181	177

In 2016, total interest paid to third parties was $181 million (2015 - $166 million, 2014 - $163 million) and total interest paid to affiliates was $27 million (2015 - $27 million, 2014 - $29 million).

The Company's borrowings, whether debentures or medium-term notes, are unsecured. As at December 31, 2016, the Company was in compliance with all covenants.

CREDIT FACILITIES

The Company currently has a $1 billion commercial paper program limit that is backstopped by committed lines of credit of $1 billion. The term of any commercial paper issued under this program may not exceed one year. The maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option. In July 2016, the Company extended the term out date of this external credit facility to July 2017, with a maturity date in July 2018.

During the first quarter of 2016, St. Lawrence terminated its credit facility and entered into new banking agreements with a new financial institution in which $9 million (US$7 million) of promissory notes were issued under the loan agreement at an interest rate of 2.98%, maturing in July 2019.

During the second quarter of 2016, St. Lawrence terminated its uncommitted demand credit facilities, and entered into new banking agreements with a new financial institution in which $8 million (US$6 million) of committed credit facilities were issued under the agreement. The credit facilities bear interest at market rates and mature in June 2019.

In May 2016, the Company did not renew its $300 million revolving credit facility that it had with Enbridge.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2016.

		December 31, 2016			December 31, 2015
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities[2]
(millions of Canadian dollars)					
Enbridge Gas Distribution Inc.	2018	**1,000**	**345**	**655**	1,300
St. Lawrence Gas Company, Inc.	2019	**17**	**15**	**2**	10
Total credit facilities		**1,017**	**360**	**657**	1,310

1 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the external credit facility.
2 Includes a $300 million revolving credit facility from the Company's ultimate parent, Enbridge.

As at December 31, 2016, the Company did not have any uncommitted demand credit facilities. As at December 31, 2015, the Company had $7 million of uncommitted demand credit facilities, of which $3 million was unutilized.

Credit facilities carried a weighted average standby fee of 0.2% on the unused portion and the draws bear interest at market rates.

12. OTHER LONG-TERM LIABILITIES

December 31,	**2016**	2015
(millions of Canadian dollars)		
Regulatory liabilities *(Note 4)*	**624**	670
Pension and OPEB liabilities *(Note 19)*	**208**	163
Long-term portion of derivative liabilities *(Note 17)*	**1**	-
Other *(Note 13)*	**13**	14
	846	847

Included in Regulatory liabilities at December 31, 2016 is $31 million (2015 - $109 million) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers beyond the next 12 months.

13. ASSET RETIREMENT OBLIGATIONS

The liability for the expected cash flows as recognized in the Consolidated Financial Statements reflected discount rates ranging from 1.65% to 3.77% (2015 - 1.65% to 3.77%). A reconciliation of movements in the Company's ARO is as follows:

December 31,	**2016**	2015
(millions of Canadian dollars)		
Obligations at beginning of year	**9**	9
Liabilities settled	**(1)**	(2)
Change in estimate	**(1)**	2
Accretion expense	**-**	-
Obligations at end of year	**7**	9
Presented as follows:		
Other long-term liabilities *(Note 12)*	**7**	9
	7	9

14. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preference shares.

COMMON SHARES

	2016		2015		2014	
December 31,	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**170.0**	**1,637**	158.9	1,437	150.6	1,287
Common shares issued	**15.6**	**280**	11.1	200	8.3	150
Balance at end of year *(Note 22)*	**185.6**	**1,917**	170.0	1,637	158.9	1,437

PREFERENCE SHARES

December 31, 2016, 2015, and 2014	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preference shares in millions)			
Group 2, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 2, Series D, Cumulative Redeemable Convertible	4	-	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	-	-
Group 5	10	-	-
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preference shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case. As at December 31, 2016, no preference shares have been redeemed.

On July 1, 2019, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference shares on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period. The Group 3, Series D preference shareholders opted not to convert their shares into Group 2, Series D preference shares effective July 1, 2014.

The Group 2, Series D preference shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder's option on July 1, 2019 and every five years thereafter.

15. STOCK OPTION AND STOCK UNIT PLANS

Enbridge's four long-term incentive compensation plans include the ISO Plan, the PSO Plan, the PSU Plan and the RSU Plan. The Company reimburses Enbridge for stock-based compensation costs associated with its employees on a quarterly basis. As at December 31, 2016, the Company did not have any employees that had options in the PSO Plan.

INCENTIVE STOCK OPTIONS

Key employees of the Company are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2016	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**2,688**	**39.43**		
Options granted	**703**	**44.06**		
Options exercised[1]	**(419)**	**28.78**		
Options cancelled	**(7)**	**44.83**		
Employee movements from other Enbridge companies	**511**	**38.56**		
Options outstanding at end of year	**3,476**	**41.54**	**6.3**	**39**
Options vested at end of year[2]	**1,957**	**35.74**	**4.8**	**33**

1 The total intrinsic value of ISOs exercised during the year ended December 31, 2016 was $10 million (2015 - $14 million; 2014 - $11 million) and cash received by Enbridge on exercise was $12 million (2015 - $10 million; 2014 - $5 million).

2 The total fair value of options vested under the ISO Plan during the year ended December 31, 2016 was $3 million (2015 and 2014 - $2 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2016**	2015	2014
Fair value per option *(Canadian dollars)*[1]	**7.37**	6.48	5.53
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	5
Expected volatility[3]	**25.1%**	19.9%	16.9%
Expected dividend yield[4]	**4.4%**	3.2%	2.9%
Risk-free interest rate[5]	**0.8%**	0.9%	1.6%

1 Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $7.01 (2015 - $6.22; 2014 - $5.45) for Canadian employees and US$6.60 (2015 - US$6.16, 2014 - US$5.35) for United States employees.

2 The expected option term is based on historical exercise practice and three years for retirement eligible employees.

3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.

4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.

5 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.

Compensation expense recorded for the year ended December 31, 2016 for ISOs was $6 million (2015 and 2014 - $4 million). At December 31, 2016 , unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $4 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan for senior officers of the Company where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two if Enbridge performs within the highest range of its performance targets. The performance multiplier is derived through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's earnings per share, adjusted for unusual non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2016 expense, multipliers of two, based upon multiplier estimates at December 31, 2016, were used for each of the 2014, 2015 and 2016 grants.

December 31, 2016	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**30**		
Units granted	**23**		
Units cancelled	**(8)**		
Units matured[1]	**(22)**		
Dividend reinvestment	**3**		
Employee movements from other Enbridge companies	**9**		
Units outstanding at end of year	**35**	**1.5**	**5**

1 The total amount paid by Enbridge during the year ended December 31, 2016 for PSUs was $1 million (2015 - $2 million; 2014 - $1 million).

Compensation expense recorded for the year ended December 31, 2016 for PSUs was $4 million (2015 - $2 million; 2014 - $5 million). As at December 31, 2016, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $2 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a RSU Plan where cash awards are paid to certain non-executive employees of the Company following a 35-month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2016	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**184**		
Units granted	**97**		
Units cancelled	**(9)**		
Units matured[1]	**(96)**		
Dividend reinvestment	**12**		
Employee movements from other Enbridge companies	**(1)**		
Units outstanding at end of year	**187**	**1.5**	**17**

1 The total amount paid by Enbridge during the year ended December 31, 2016 for RSUs was $5 million (2015 and 2014 - $5 million).

Compensation expense recorded for the year ended December 31, 2016 for RSUs was $6 million (2015 - $6 million; 2014 - $5 million). As at December 31, 2016 , unrecognized compensation expense related to non-vested units granted under the RSU Plan was $6 million and is expected to be fully recognized over a weighted average period of approximately two years.

16. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

Changes in AOCI for the years ended December 31, 2016, 2015, and 2014, are as follows:

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2016	**(5)**	**6**	**(7)**	**(6)**
Other comprehensive loss retained in AOCI	**(14)**	**(2)**	**(2)**	**(18)**
Other comprehensive loss reclassified to earnings	**6**	**-**	**-**	**6**
Income tax on amounts retained in AOCI	**3**	**-**	**-**	**3**
Income tax on amounts reclassified to earnings	**(1)**	**-**	**1**	**-**
	(6)	**(2)**	**(1)**	**(9)**
Balance at December 31, 2016	**(11)**	**4**	**(8)**	**(15)**

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2015	8	(2)	(7)	(1)
Other comprehensive income/(loss) retained in AOCI	(24)	8	-	(16)
Other comprehensive loss reclassified to earnings	6	-	-	6
Income tax on amounts retained in AOCI	6	-	-	6
Income tax on amounts reclassified to earnings	(1)	-	-	(1)
	(13)	8	-	(5)
Balance at December 31, 2015	(5)	6	(7)	(6)

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2014	70	(5)	-	65
Other comprehensive income/(loss) retained in AOCI	(84)	3	(9)	(90)
Other comprehensive loss reclassified to earnings	-	-	-	-
Income tax on amounts retained in AOCI	22	-	2	24
	(62)	3	(7)	(66)
Balance at December 31, 2014	8	(2)	(7)	(1)

17. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and OCI are subject to movements in natural gas prices, foreign exchange rates and interest rates (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them.

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer; therefore, the net exposure to the Company is nil.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. The

Company generates certain revenues, and holds a subsidiary that is denominated in USD. As a result, the Company's earnings, cash flows, and OCI are exposed to fluctuations resulting from USD exchange rate variability.

The Company implemented a policy in 2016 to hedge a portion of USD denominated unregulated storage revenue exposures. Qualifying derivative instruments are used to hedge anticipated USD denominated revenues and to manage variability in cash flows.

A portion of the Company's purchases of natural gas are denominated in USD and as a result there is exposure to fluctuations in the exchange rate of the USD against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the Company has no net exposure to movements in the foreign exchange rate on natural gas purchases.

Interest Rate Risk
The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps are used to mitigate the volatility of short-term interest rates on interest expense related to variable rate debt.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances. The Company uses qualifying derivative instruments to manage interest rate risk.

The Company's portfolio mix of fixed and variable rate debt instruments is monitored by its ultimate parent company, Enbridge. The Company does not typically manage the fair value of its debt instruments.

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the financial statement line item in the Consolidated Statements of Financial Position and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges or net investment hedges at December 31, 2016 or 2015.

The Company generally has a common practice of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2016	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable and other					
Interest rate contracts	**-**	**-**	**-**	**-**	**-**
Other long-term liabilities					
Foreign exchange contracts	**(1)**	**-**	**(1)**	**-**	**(1)**
Total net derivative liabilities					
Interest rate contracts	**-**	**-**	**-**	**-**	**-**
Foreign exchange contracts	**(1)**	**-**	**(1)**	**-**	**(1)**

December 31, 2015	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable and other					
Interest rate contracts	(14)	-	(14)	-	(14)
Total net derivative liabilities					
Interest rate contracts	(14)	-	(14)	-	(14)

The Company's derivative instruments relating to interest rate contracts mature through 2017 and have a notional principal of $8 million for interest rate contracts for short-term borrowings (2015 - $154 million) and nil for interest rate contracts on the anticipated issuance of long-term debt (2015 - $162 million).

The Company's derivative instruments relating to foreign exchange forward contracts mature through 2022 and have a notional principal of $13 million for the sale of foreign exchange (2015 – nil).

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Amount of unrealized loss recognized in OCI Cash flow hedges			
Interest rate contracts	**(13)**	(24)	(84)
Foreign exchange contracts	**(1)**	-	-
	(14)	(24)	(84)
Amount of loss reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**(3)**	(2)	
	(3)	(2)	-
Amount of loss reclassified from AOCI to earnings *(ineffective portion)*			
Interest rate contracts[1]	**(3)**	(4)	
	(3)	(4)	-

1 Reported within Interest expense in the Consolidated Statements of Earnings.

The Company estimates that nil in AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on interest and foreign exchange rates in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is one month at December 31, 2016.

LIQUIDITY RISK
Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments *(Notes 22 and 23)* as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under committed credit facilities and long-term debt, which includes debentures and MTNs and, if necessary, additional liquidity is available through intercompany transactions with its ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable the Company to fund all anticipated requirements. The Company maintains a current MTN shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. The Company also maintains committed credit facilities *(Note 11)* with a diversified group of banks and institutions. The Company is in compliance with all the terms and conditions of its committed credit facilities as at December 31, 2016. As a result, all credit facilities are available to the Company and the banks are obligated to fund the Company under the terms of the facilities.

CREDIT RISK
Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts *(Note 6),* which totaled $33 million at December 31, 2016 (December 31, 2015 - $34 million).

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate.

Entering into derivative financial instruments may also result in exposure to credit risk. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

The Company did not have group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the Canadian financial institutions or European financial institutions counterparty segments at December 31, 2016 or 2015.

FAIR VALUE MEASUREMENTS
The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable

market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company categorizes its derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company does not have any derivative instruments classified as Level 1.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps for which observable inputs can be obtained.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support a Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2016, the Company had Level 2 derivative assets with fair value of nil (2015 - nil) and Level 2 derivative liabilities with fair value of $1 million (2015 - $14 million).

The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers between levels as at December 31, 2016 or 2015.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted market prices are not available for fair value measurement in which case these investments are recorded at cost. The Company's investment in IPL System Inc., an affiliate company, is recorded at fair value. At December 31, 2016, the fair value of the investment was $825 million (2015 - $825 million). The fair value of the Company's investment is classified as a Level 2 measurement and as at December 31, 2016 and 2015 the fair value approximated its cost and redemption value and therefore no amount was recognized in OCI.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2016, the Company's long-term debt, including the current portion had a carrying value of $3,983 million (2015 - $3,683 million) and a fair value of $4,585 million (2015 - $4,159 million).

The fair value of other financial assets and liabilities other than derivative instruments and long-term debt approximate their cost due to the short period to maturity.

18. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Earnings before income taxes	**239**	245	252
Federal statutory income tax rate	**15.0%**	15.0%	15.0%
Federal income taxes at statutory rate	**36**	37	38
Increase/(decrease) resulting from:			
Provincial and state income taxes	**(27)**	5	3
Effects of rate regulated accounting[1,2]	**(25)**	(22)	(25)
Non-taxable intercompany distributions[2]	**(9)**	(9)	(9)
Part VI.1 tax, net of federal Part I tax deduction[2]	**35**	-	-
Other[3]	**(1)**	-	(1)
Income taxes	**9**	11	6
Effective income tax rate	**3.8%**	4.5%	2.4%

1 During 2016, 2015 and 2014, previously collected costs for future removal and site restoration were refunded to customers that resulted in a decrease in income taxes of $22 million at December 31, 2016 (2015 - $24 million, 2014 - $26 million).
2 The provincial tax component of these items is included in "Provincial and state income taxes" above.
3 Included in "Other" are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals & entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**236**	243	249
United States	**3**	2	3
	239	245	252
Current income taxes			
Canada	**32**	(4)	2
United States	**(1)**	(1)	1
	31	(5)	3
Deferred income taxes			
Canada	**(24)**	14	3
United States	**2**	2	-
	(22)	16	3
Income taxes	**9**	11	6

COMPONENTS OF DEFERRED INCOME TAXES
Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2016**	2015
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(637)**	(600)
Regulatory assets	**(101)**	(86)
Deferrals	**(8)**	-
Other	**-**	(1)
Total deferred income tax liabilities	**(746)**	(687)
Deferred income tax assets		
Future removal and site restoration reserves	**153**	146
Retirement and postretirement benefits	**37**	30
Minimum tax credits	**13**	9
Loss carryforwards	**4**	-
Financial derivatives	**4**	2
Other	**3**	2
Total deferred income tax assets	**214**	189
Net deferred income tax liabilities	**(532)**	(498)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 6)*	**-**	18
Deferred amounts and other assets *(Note 8)*	**-**	8
Total deferred income tax assets	**-**	26
Liabilities		
Deferred income taxes	**(532)**	(524)
Total deferred income tax liabilities	**(532)**	(524)
Net deferred income tax liabilities	**(532)**	(498)

The Company has assessed all tax positions. As a result, no significant adjustments were required to be made to the income tax provisions for the year ended December 31, 2016.

The Company has not provided for deferred income taxes on the difference between the carrying value of its foreign subsidiaries and their corresponding tax bases as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying value of the investment and its tax basis is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries is $30 million (2015 - $30 million). If such earnings were remitted, in the form of dividends or otherwise, the Company may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

The Company and its subsidiaries are subject to taxation in Canada and the Unites States. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario). The Company's 2012 to 2015 taxation years are still open for audit in Canada.

19. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS
The Company provides a non-contributory basic pension plan that provides defined benefit or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees.

A measurement date of December 31, 2016 was used to determine the plan assets and accrued benefit obligation for the pension plans.

Defined Benefit Plans
Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation-indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective date of the most recent actuarial valuation was December 31, 2013. The effective date of the next required actuarial valuation is December 31, 2016.

Defined Contribution Plans
Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

OTHER POSTRETIREMENT BENEFITS
The Company also provides OPEB, which primarily includes supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS
The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension		OPEB	
December 31,	**2016**	2015	**2016**	2015
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,025**	1,046	**120**	117
Service cost	**32**	35	**1**	1
Interest cost	**35**	41	**5**	5
Actuarial loss/(gain)	**51**	(54)	**2**	(1)
Benefits paid	**(46)**	(43)	**(4)**	(4)
Other	**1**	-	**(1)**	2
Benefit obligation at end of year	**1,098**	1,025	**123**	120
Change in plan assets				
Fair value of plan assets at beginning of year	**969**	960	**17**	13
Actual return on plan assets	**73**	49	**1**	-
Employer's contributions	**1**	3	**5**	5
Benefits paid	**(46)**	(43)	**(4)**	(4)
Other	**1**	-	**(2)**	3
Fair value of plan assets at end of year	**998**	969	**17**	17
Underfunded status at end of year	**(100)**	(56)	**(106)**	(103)
Presented as follows:				
Deferred amounts and other assets *(Note 8)*	**3**	6	**3**	2
Accounts payable and other *(Note 10)*	**-**	-	**(4)**	(4)
Other long-term liabilities *(Note 12)*	**(103)**	(62)	**(105)**	(101)

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2016**	2015	2014	**2016**	2015	2014
Discount rate	**3.9%**	4.2%	4.0%	**3.9%**	4.2%	4.0%
Average rate of salary increases	**3.5%**	3.4%	3.7%	**3.5%**	3.4%	3.7%

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2016**	2015	2014	**2016**	2015	2014
(millions of Canadian dollars)						
Benefits earned during the year	**32**	35	25	**1**	1	1
Interest cost on projected benefit obligations	**35**	41	43	**5**	5	6
Expected return on plan assets	**(60)**	(62)	(59)	**(1)**	(1)	(1)
Amortization of actuarial loss	**14**	19	16	**-**	1	-
Net defined benefit costs on an accrual basis	**21**	33	25	**5**	6	6
Defined contribution benefit costs	**1**	1	1	**-**	-	-
Net benefit cost recognized on an accrual basis	**22**	34	26	**5**	6	6
Net amount recognized in OCI						
Net actuarial (gain)/loss[1]	**-**	-	-	**2**	-	9
Total amount recognized in OCI	**-**	-	-	**2**	-	9
Total net benefit cost on an accrual basis and amount recognized in OCI	**22**	34	26	**7**	6	15

1 Unamortized actuarial losses included in AOCI, before tax, were $11 million relating to OPEB at December 31, 2016 (2015 - $9 million, 2014 - $9 million).

The Company estimates that approximately $16 million related to pension plans and OPEB at December 31, 2016 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Actuarial loss	**16**	**-**	**16**
	16	**-**	**16**

Pension and OPEB costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension and OPEB costs due to the regulatory mechanism in place. As a result, the net pension and OPEB expense primarily consists of OEB approved pension and OPEB costs.

Regulatory adjustments were recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers, respectively, in future rates *(Note 4)*. For the year ended December 31, 2016, an offsetting regulatory liability increased by $10 million (2015 - nil) and has been recorded to the extent pension and OPEB costs are expected to be refunded to customers in future rates.

The assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2016**	2015	2014	**2016**	2015	2014
Discount rate - service cost	**4.3%**	4.0%	5.0%	**4.3%**	4.0%	5.0%
Discount rate - interest cost	**3.5%**	4.0%	5.0%	**3.5%**	4.0%	5.0%
Average rate of return on pension plan assets	**6.5%**	6.8%	6.8%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.4%**	3.7%	3.5%	**3.4%**	3.7%	3.5%

MEDICAL COST TRENDS
The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in Which Ultimate Medical Cost Trend Rate Assumption is Achieved
Drugs	6.6%	4.3%	2034
Other medical and dental	4.5%	4.5%	-

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $13 million in the benefit obligation and an increase of nil in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $11 million in the benefit obligation and a decrease of nil in benefit and interest costs.

PLAN ASSETS
The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2016**	2015	**2016**	2015
Expected rate of return	**6.5%**	6.8%	**-**	-

Target Mix for Plan Assets

Equity securities	44.5%
Fixed income securities	40.0%
Other	15.5%

Major Categories of Plan Assets
Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2016, the pension assets were invested in 47% (2015 - 47%) in equity securities, 36% (2015 - 36%) in fixed income securities and 17% (2015 - 17%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $24 million (2015 - $29 million) have been excluded from the table below.

	2016				2015			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension Benefits								
Cash and cash equivalents	**7**	**-**	**-**	**7**	10	-	-	10
Fixed income securities								
Canadian government real return bonds	**74**	**-**	**-**	**74**	73	-	-	73
Canadian corporate bond index fund	**140**	**-**	**-**	**140**	133	-	-	133
Canadian government bond index fund	**128**	**-**	**-**	**128**	128	-	-	128
Corporate bonds and debentures	**5**	**-**	**-**	**5**	4	-	-	4
United States debt index fund	**2**	**-**	**-**	**2**	2	-	-	2
Equity								
Canadian equity securities	**67**	**-**	**-**	**67**	71	-	-	71
Canadian equity funds	**142**	**-**	**-**	**142**	128	-	-	128
United States equity securities	**2**	**-**	**-**	**2**	1	-	-	1
United States equity funds	**108**	**-**	**-**	**108**	100	-	-	100
Global equity funds	**74**	**72**	**-**	**146**	71	79	-	150
Infrastructure[4]	**-**	**-**	**90**	**90**	-	-	96	96
Real estate[4]	**-**	**-**	**63**	**63**	-	-	51	51
Forward currency contracts	**-**	**-**	**-**	**-**	-	(7)	-	(7)
	749	**72**	**153**	**974**	721	72	147	940
OPEB								
Cash and cash equivalents	**-**	**-**	**-**	**-**	1	-	-	1
Fixed income securities								
United States government and government agency bonds	**7**	**-**	**-**	**7**	6	-	-	6
Equity								
United States equity fund	**5**	**-**	**-**	**5**	5	-	-	5
Global equity fund	**5**	**-**	**-**	**5**	5	-	-	5
	17	**-**	**-**	**17**	17	-	-	17

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair values of the infrastructure and real estate investments are established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2016**	2015
(millions of Canadian dollars)		
Balance at beginning of year	**147**	69
Unrealized and realized gains	**13**	26
Purchases and settlements, net	**(7)**	52
Balance at end of year	**153**	147

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension		OPEB	
Year ended December 31,	**2016**	2015	**2016**	2015
(millions of Canadian dollars)				
Total contributions	**1**	4	**5**	5

The contributions expected to be paid in 2017 for pension is $34 million and for OPEB is $4 million.

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2017	2018	2019	2020	2021	2022-2026
(millions of Canadian dollars)						
Expected future benefit payments	53	55	56	58	60	326

20. SEVERANCE COSTS

Included in Operating and administrative expense for the year ended December 31, 2016 is $20 million (2015 - $12 million) in severance costs related to termination benefits to employees. This resulted from Enbridge-wide reductions of workforce that occurred in October 2016 and November 2015 that affected approximately 5% of Enbridge's workforce in each respective year.

In 2016, $9 million was paid with the remaining $11 million to be paid in 2017, and is included in Accounts payable and other as at December 31, 2016.

In 2015, $4 million was paid with the remaining $8 million paid in 2016, and was included in Accounts payable and other as at December 31, 2015.

21. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Regulatory assets *(Note 4)*	**158**	532	(732)
Regulatory liabilities *(Note 4)*	**(127)**	(178)	(102)
Restricted cash *(Note 5)*	**(58)**	-	-
Accounts receivable and other[1,2]	**(39)**	34	24
Gas inventories	**35**	17	(181)
Deferred amounts and other assets[1]	**-**	-	(3)
Accounts payable and other[1,2]	**109**	(84)	(92)
Other long-term liabilities[1]	**-**	4	55
	78	325	(1,031)

1 The cash flow impacts of regulatory assets and liabilities have been separately disclosed and are not included.
2 Includes amounts related to affiliated companies.

22. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Enbridge Energy Distribution Inc.			
Common share dividends declared	**237**	223	204
IPL System Inc. *(Note 17)*			
Dividend income	**63**	63	63
Interest expense *(Note 11)*	**27**	27	27
Enbridge			
Purchase of treasury and other management services	**49**	50	41
Interest expense *(Note 11)*	**-**	-	2
Part IV.1 tax reimbursement *(Note 18)*	**5**	-	-
Tidal Energy Marketing Inc.			
Purchase of natural gas	**17**	23	41
Revenue from optimization services	**8**	8	8
Tidal Energy Marketing (U.S.) LLC			
Purchase of natural gas	**26**	24	57
Aux Sable Canada LP			
Purchase of natural gas	**16**	62	16
Gazifère Inc.			
Revenue from wholesale service, including gas sales	**30**	40	31
Vector Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**20**	28	27
Vector Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**1**	2	2
Alliance Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**2**	28	26
Alliance Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**4**	22	20
Niagara Gas Transmission Limited			
Purchase of gas transportation services	**2**	2	2
2193914 Canada Limited			
Purchase of gas transportation services	**2**	1	2

The Company had related party balances as follows:

December 31,	**2016**	2015
(millions of Canadian dollars)		
Common share ownership from parent company		
Enbridge Energy Distribution Inc. *(Note 14)*	**1,917**	1,637
Dividend payable	**59**	56
Investment in affiliate company *(Note 17)*		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company *(Note 11)*		
IPL System Inc.	**375**	375
Interest payable	**2**	2
Note payable to affiliate company *(Note 11)*		
Enbridge (U.S.) Inc.	**34**	40
Other accounts receivable/(payable)		
Gazifère Inc.	**5**	3
Enbridge	**5**	(4)
Enbridge Employee Services Inc.	**(13)**	(13)
Tidal Energy Marketing (U.S.) LLC	**(8)**	(4)
Enbridge Pipelines Inc.	**(6)**	-
Tidal Energy Marketing Inc.	**(4)**	-
Vector Pipeline Limited Partnership (U.S.)	**(2)**	(1)
Aux Sable Canada LP	**-**	(2)
Alliance Pipeline Limited Partnership (Canadian)	**-**	(2)
Alliance Pipeline Limited Partnership (U.S.)	**-**	(2)
Other accounts receivable	**1**	2
Other accounts payable	**(1)**	(1)

Financing Transactions
The Company has invested in Class D, non-voting, redeemable, retractable preference shares of IPL System Inc., an affiliate under common control. At December 31, 2016, the investment of $825 million (2015 - $825 million) in these shares resulted in a weighted average dividend yield of 7.60%.

At December 31, 2016, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.50%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preference shares of the Company. For the year ended December 31, 2016, interest paid amounted to $27 million (2015 - $27 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 1.1% and is payable on demand.

Treasury and Other Management Services
Enbridge provides treasury and other management services and charges the Company on a cost recovery basis.

Part IV.1 Tax Reimbursement
The Company entered into an agreement with Enbridge for the transfer of Part VI.1 tax and the related Part 1 tax deduction. The Company received a non-taxable reimbursement relating to the transfer.

Natural Gas Purchases
The Company contracted for the purchase of natural gas from Aux Sable Canada LP, Tidal Energy

Marketing Inc. and Tidal Energy Marketing (U.S.) LLC, related entities under common control, at prevailing market prices and under normal trade terms. Contractual obligations under the Tidal Energy Marketing (U.S.) LLC contract are 2017 to 2018 - $3 million, 2019 to 2020 – nil and thereafter - nil.

Optimization Services
The Company provides pipeline and storage optimization services to Tidal Energy Marketing Inc., an affiliated entity under common control.

Wholesale Service
These gas procurement and transportation services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Transportation Services
The Company contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control, and Niagara Gas Transmission Limited and 2193914 Canada Limited. Contractual obligations under the Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian) and Niagara Gas Transmission Limited contracts are 2017 to 2018 - $46 million, 2019 to 2020 - $43 million and thereafter – $101 million.

Trade Receivables and Payables
The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other shared corporate services to affiliates on a fully-allocated cost basis. Market prices, if they are reasonably determinable, are charged for affiliate services that are not shared corporate services. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

Other Transactions
The Company and affiliates invoice on a monthly basis and amounts are due and paid on a monthly basis.

23. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has signed contracts for the purchase of services, pipe and other materials, as well as natural gas and transportation, totaling $4,729 million. The amounts which are expected to be paid in the next five years are $1,216 million, $630 million, $599 million, $513 million, and $465 million, respectively, and $1,306 million thereafter. Included in these amounts are right-of-way payments, estimated to be approximately $2 million per year, related to cancellable gas storage lease payments that are reasonably likely to occur for the remaining life of all storage reservoirs, which has been assumed to be 65 years.

Minimum future payments under operating leases are estimated at $2 million in aggregate. Estimated annual lease payments for the years ended December 31, 2016 through 2021 are $2 million, nil, nil, nil and nil, respectively. Total rental expense for operating leases, classified in Operating and administrative expense, was $2 million for the year ended December 31, 2016, and $3 million for each of the years ended December 31, 2015 and 2014.

The Company, Enbridge, and Enbridge Pipeline Inc., in aggregate, have access to $95 million of letters of credit that they can issue, of which $33 million was unutilized as at December 31, 2016. The total outstanding letters of credit that related to the Company as at December 31, 2016 was $8 million. The Company had access to $95 million of letters of credit that it could issue, of which $37 million was unutilized as at December 31, 2015. The total outstanding letters of credit that related to the Company as at December 31, 2015 was $5 million.

CONTINGENCIES

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, a former owner of part of the Historic Distillery District (Wyndham Court Canada Inc.) commenced an action in the Ontario Court of Justice (General Division) against the Company alleging that coal tar originating from the Company's Station A MGP in Toronto had migrated to its lands. The Company entered into a Tolling Agreement with Wyndham Court Canada Inc. pursuant to which this action was discontinued, without prejudice to the right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham Court Canada Inc. sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape).

Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but the required steps in the discovery process were not completed by the plaintiff. The Company has brought a motion to dismiss the plaintiff's action for delay. At present, it is unknown when or if the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2016 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

OTHER LITIGATION
The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a significant impact on the Company's consolidated financial position or results of operations.

ENBRIDGE GAS DISTRIBUTION INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2017

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Gas Distribution Inc.

Financial Reporting
Management of Enbridge Gas Distribution Inc. (the Company) is responsible for the accompanying consolidated financial statements and all related financial information, including Management's Discussion and Analysis. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) is responsible for all aspects related to governance of the Company. The Board has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Board reviews the consolidated financial statements and the internal controls as they relate to financial reporting. The Board approves the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with U.S. GAAP and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

(Signed)

James Sanders
President

(Signed)

Wendy Zelond
Vice President, Finance

February 16, 2018

February 16, 2018

Independent Auditor's Report

To the Shareholders of
Enbridge Gas Distribution Inc.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and their subsidiaries as at December 31, 2017 and December 31, 2016 and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2017**	2016
(millions of dollars)		
Operating Revenues		
Gas commodity and distribution revenue *(Note 18)*	**2,760**	2,437
Transportation of gas for customers	**418**	330
Other revenue *(Note 18)*	**114**	100
Total operating revenues	**3,292**	2,867
Operating Expenses		
Gas commodity and distribution costs *(Note 18)*	**2,032**	1,636
Operating and administrative *(Notes 12 and 18)*	**520**	534
Depreciation and amortization *(Notes 7 and 8)*	**330**	322
Earnings sharing *(Note 5)*	**24**	3
Total operating expenses	**2,906**	2,495
Operating Income	**386**	372
Other income *(Note 19)*	**64**	73
Interest expense, net *(Notes 10, 14 and 18)*	**(214)**	(206)
Earnings before income taxes	**236**	239
Income tax recovery/(expense) *(Note 15)*	**14**	(9)
Earnings	**250**	230
Preference share dividends *(Note 11)*	**(2)**	(2)
Earnings attributable to the common shareholder	**248**	228

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2017**	2016
(millions of dollars)		
Earnings	**250**	230
Other comprehensive income/(loss), net of tax *(Notes 13 and 14)*		
Change in unrealized loss on cash flow hedges	**—**	(11)
Reclassification to earnings of realized loss on cash flow hedges	**3**	5
Actuarial loss on other postretirement benefits (OPEB) *(Note 16)*	**(2)**	(1)
Foreign currency translation adjustment	**(2)**	(2)
Other comprehensive loss, net of tax	**(1)**	(9)
Comprehensive income	**249**	221
Preference share dividends	**(2)**	(2)
Comprehensive income attributable to the common shareholder	**247**	219

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Preference Shares *(Note 11)*	Common Shares *(Note 11)*	Additional Paid-in Capital	Retained Earnings/ (Deficit)	Accumulated Other Comprehensive Loss *(Note 13)*	Total
(millions of dollars)						
December 31, 2015	100	1,637	1,148	71	(6)	2,950
Other comprehensive loss, net of tax	—	—	—	—	(9)	(9)
Common shares issued	—	280	—	—	—	280
Earnings attributable to the common shareholder	—	—	—	228	—	228
Common shares dividends declared *(Note 18)*	—	—	—	(237)	—	(237)
December 31, 2016	100	1,917	1,148	62	(15)	3,212
Other comprehensive loss, net of tax	**—**	**—**	**—**	**—**	**(1)**	**(1)**
Common shares issued	**—**	**500**	**—**	**—**	**—**	**500**
Earnings attributable to the common shareholder	**—**	**—**	**—**	**248**	**—**	**248**
Common shares dividends declared *(Note 18)*	**—**	**—**	**—**	**(600)**	**—**	**(600)**
December 31, 2017	**100**	**2,417**	**1,148**	**(290)**	**(16)**	**3,359**

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2017**	2016
(millions of dollars)		
Operating activities		
Earnings	**250**	230
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization *(Notes 7 and 8)*	**330**	322
Deferred income tax expense *(Note 15)*	**(19)**	(22)
Net defined pension and other postretirement benefit obligations (OPEB) costs	**(25)**	30
Other	**1**	4
Changes in operating assets and liabilities *(Note 17)*	**27**	78
Net cash provided by operating activities	**564**	642
Investing activities		
Capital expenditures	**(407)**	(545)
Additions to intangible assets	**(392)**	(57)
Change in construction payable	**(1)**	(138)
Net cash used in investing activities	**(800)**	(740)
Financing activities		
Net change in short-term borrowings *(Note 10)*	**615**	(248)
Net change in short-term borrowings from affiliates *(Note 18)*	**—**	(6)
Term note issuances, net of issue costs *(Note 10)*	**298**	309
Term note repayments	**(500)**	(7)
Common shares issued *(Notes 11 and 18)*	**500**	280
Common share dividends	**(659)**	(233)
Preference share dividends	**(2)**	(2)
Net cash provided by financing activities	**252**	93
Net increase/(decrease) in cash and cash equivalents	**16**	(5)
Cash and cash equivalents at beginning of year	**4**	9
Cash and cash equivalents at end of year	**20**	4
Supplementary cash flow information		
Cash paid for income taxes	**4**	5
Cash paid for interest, net of amounts capitalized *(Note 10)*	**208**	194

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2017**	2016
(millions of dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents *(Note 2)*	**20**	4
Restricted cash	**44**	58
Accounts receivable and other *(Notes 5, 6, 14 and 15)*	**849**	655
Due from affiliates *(Note 18)*	**43**	16
Gas inventory	**492**	512
Assets held for sale, current *(Note 4)*	**15**	—
	1,463	1,245
Property, plant and equipment, net *(Note 7)*	**7,532**	7,418
Investment in affiliate *(Notes 14 and 19)*	**825**	825
Deferred amounts and other assets *(Notes 5, 15 and 16)*	**597**	576
Intangible assets, net *(Note 8)*	**486**	158
Assets held for sale, long-term *(Note 4)*	**110**	—
Total assets	**11,013**	10,222
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings *(Note 10)*	**960**	351
Short-term borrowings from affiliate *(Notes 10 and 18)*	**—**	34
Accounts payable and other *(Notes 5, 9, 14 and 16)*	**662**	807
Due to affiliates *(Note 18)*	**87**	95
Current portion of long-term debt *(Note 10)*	**—**	500
Liabilities held for sale, current *(Note 4)*	**43**	—
	1,752	1,787
Long-term debt *(Note 10)*	**3,760**	3,470
Other long-term liabilities *(Notes 5, 14 and 17)*	**1,142**	846
Deferred income taxes *(Note 15)*	**591**	532
Loans from affiliate *(Notes 10 and 18)*	**375**	375
Liabilities held for sale, long-term *(Note 4)*	**34**	—
Total liabilities	**7,654**	7,010
Shareholders' equity		
Share capital *(Note 11)*		
Preference shares *(convertible; 4 outstanding at December 31, 2017 and December 31, 2016)*	**100**	100
Common shares *(213 and 186 outstanding at December 31, 2017 and 2016, respectively)*	**2,417**	1,917
Additional paid-in capital	**1,148**	1,148
Retained earnings/(deficit)	**(290)**	62
Accumulated other comprehensive loss *(Note 13)*	**(16)**	(15)
Total shareholders' equity	**3,359**	3,212
Total liabilities and shareholders' equity	**11,013**	10,222

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

(Signed)

James Sanders
President

(Signed)

David G. Unruh
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS OVERVIEW

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence Gas), an asset held for sale *(Note 4)*. The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

2. SIGNIFICANT ACCOUNTING POLICIES

These Consolidated Financial Statements are prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

In 2014, Canadian securities regulators approved the extension of the Company's exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. The Company is in the process of obtaining further extension of this exemptive relief beyond January 1, 2019.

BASIS OF PRESENTATION AND USE OF ESTIMATES
The preparation of Consolidated Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the Consolidated Financial Statements. Significant estimates and assumptions used in the preparation of the Consolidated Financial Statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities; unbilled revenues; allowance for doubtful accounts; carrying value of gas inventory; depreciation rates and carrying value of property, plant and equipment; amortization rates and carrying value of intangible assets; valuation of stock-based compensation; fair value of financial instruments; provisions for income taxes; assumptions used to measure retirement and OPEB; commitments and contingencies; and fair value of asset retirement obligations (ARO). Actual results could differ from these estimates.

Effective September 30, 2017, the Company combined Cash and cash equivalents and amounts previously presented as Bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements. As at December 31, 2017, $4 million (2016 - $72 million) of Bank indebtedness has been combined with Cash and cash equivalents on the Company's Consolidated Statements of Financial Position. Net cash provided by financing activities in the Company's Consolidated Statements of Cash Flows have been reduced by $45 million for the year ended December 31, 2016 to reflect this change.

PRINCIPLES OF CONSOLIDATION
The Consolidated Financial Statements include the accounts of the Company and its subsidiary. All significant intercompany accounts and transactions are eliminated upon consolidation *(Note 4)*.

REGULATION
The utility operations of the Company within Ontario are regulated by the Ontario Energy Board (OEB), while the utility operations of St. Lawrence Gas are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities *(Note 5)*.

As a result of rate regulation accounting, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation accounting, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. The Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

REVENUE RECOGNITION

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise areas.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

PUSH-DOWN ACCOUNTING

The Company elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted U.S. GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by the Company. Upon adopting push-down accounting, the historical cost of the Company's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in interest rates and foreign exchange. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges at December 31, 2017 or 2016.

Cash Flow Hedges
The Company uses cash flow hedges to manage its exposure to changes in currency exchange rates related to unregulated storage revenue and changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/loss (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives
The Company recognizes the fair value of derivative instruments on the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs as a direct deduction from the carrying amount of the related debt liability. These costs are amortized using the effective interest rate method over the life of the related debt instrument and are recorded in Interest expense.

INCOME TAXES
The liability method of accounting for income taxes is followed. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in income taxes. Deferred tax liabilities and assets are classified as noncurrent in the Consolidated Statements of Financial Position.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as approved by the Regulators for rate-making purposes. As a result, rates do not include the recovery of deferred income taxes related to temporary differences. A corresponding deferred income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates *(Note 5)*.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION
Foreign currency transactions are those transactions denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of

exchange in effect at the date of the Consolidated Statement of Financial Position. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The functional currency of the Company's only foreign operation, St. Lawrence Gas, is the United States dollar (USD). The effects of translating the financial statements of St. Lawrence Gas to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI). Asset and liability accounts are translated at the exchange rates in effect on the date of the Consolidated Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased, net of bank indebtedness that is subject to cash pooling arrangements.

RESTRICTED CASH
Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific agreements, are presented as Restricted cash on the Consolidated Statements of Financial Position. Restricted cash represents funds received from the Green Investment Fund program. The cash flow impact of this item is included in changes of operating assets and liabilities on the Consolidated Statements of Cash Flows.

GAS INVENTORY
Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction as authorized by the Regulators. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the Regulators. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation until the last asset in the pool is disposed of. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily include: costs which the Regulators have permitted, or are expected to permit, to be recovered through future rates; deferred income taxes; and derivative financial instruments.

INTANGIBLE ASSETS
Prior to January 1, 2017, Intangible assets consisted primarily of the Company's Customer Information System (CIS) and software costs, including the Work and Asset Management Solution (WAMS). The Company capitalizes costs incurred during the application development stage of internal use software projects. Those intangible assets are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use. Beginning January 1, 2017, intangible assets also include emission allowances purchased in order to meet greenhouse gas compliance obligations *(Note 8)*.

ASSET RETIREMENT OBLIGATIONS
Asset Retirement Obligations (ARO) associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

RETIREMENT AND POSTRETIREMENT BENEFITS
The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality.

The Company uses mortality tables issued by the Canadian Institute of Actuaries tables (revised in 2014) to measure its benefit obligations of its pension plan. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipate making under each of the respective plans. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Interest cost of pension plan obligations;
- Expected return on pension plan assets;
- Amortization of the prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

The Company records regulatory adjustments to reflect the difference between pension expense and OPEB costs for accounting purposes and the pension expense and OPEB costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension expense or OPEB costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION

Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISOs granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility.

Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of Enbridge's shares.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or a liability has been incurred, and the amount of the impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Clarifying the Definition of a Business in an Acquisition

Effective January 1, 2017, the Company early adopted ASU 2017-01 on a prospective basis. The new standard was issued with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (disposals) of assets or businesses.

Accounting for Intra-Entity Asset Transfers
Effective January 1, 2017, the Company early adopted ASU 2016-16 on a modified retrospective basis. The new standard was issued with the intent of improving the accounting for the income tax consequences of intra-entity asset transfers other than inventory. Under the new guidance, an entity should recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

Improvements to Employee Share-Based Payment Accounting
Effective January 1, 2017, the Company adopted ASU 2016-09 and applied certain amendments on a modified retrospective basis with the remaining amendments applied on a prospective basis. The new standard was issued with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES
Improvements to Accounting for Hedging Activities
ASU 2017-12 was issued in August 2017 with the objective of better aligning a company's risk management activities and the resulting hedge accounting reflected in the financial statements. The accounting update allows cash flow hedging of contractually specified components in financial and non-financial items. Under the new guidance, hedge ineffectiveness is no longer required to be measured and hedging instruments' fair value changes will be recorded in the same income statement line as the hedged item. The ASU also allows the initial quantitative hedge effectiveness assessment to be performed at any time before the end of the quarter in which the hedge is designated. After initial quantitative testing is performed, an ongoing qualitative effectiveness assessment is permitted. The accounting update is effective January 1, 2019, with early adoption permitted, and is to be applied on a modified retrospective basis. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements.

Clarifying Guidance on the Application of Modification Accounting on Stock Compensation
ASU 2017-09 was issued in May 2017 with the intent to clarify the scope of modification accounting and when it should be applied to a change to the terms or conditions of a share based payment award. Under the new guidance, modification accounting is required for all changes to share based payment awards, unless all of the following are met: 1) there is no change to the fair value of the award, 2) the vesting conditions have not changed, and 3) the classification of the award as an equity instrument or a debt instrument has not changed. The accounting update is effective January 1, 2018 and will be applied on a prospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Improving the Presentation of Net Periodic Benefit Cost related to Defined Benefit Plans
ASU 2017-07 was issued in March 2017 primarily to improve the income statement presentation of the components of net periodic pension cost and net periodic postretirement benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. In addition, only the service cost component of net benefit cost is eligible for capitalization. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis for the statement of earnings presentation component and a prospective basis for the capitalization component. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Clarifying Guidance on Derecognition and Partial Sales of Nonfinancial Assets
ASU 2017-05 was issued in February 2017 with the intent of clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets. The ASU clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset, and amends the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. The accounting update is

effective January 1, 2018 and will be applied on a modified retrospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows
ASU 2016-18 was issued in November 2016 with the intent to clarify guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the statement of cash flows. The accounting update requires that changes in restricted cash and restricted cash equivalents be included within cash and cash equivalents when reconciling the opening and closing period amounts shown on the statement of cash flows. The Company currently presents the changes in restricted cash and restricted cash equivalents under operating activities in the Consolidated Statement of Cash Flows. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. The Company will amend the presentation in the Consolidated Statement of Cash Flows to include restricted cash and restricted cash equivalents with cash and cash equivalents and retrospectively reclassify all periods presented.

Simplifying Cash Flow Classification
ASU 2016-15 was issued in August 2016 with the intent of reducing diversity in practice of how certain cash receipts and cash payments are classified in the Consolidated Statement of Cash Flows. The new guidance addresses eight specific presentation issues. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. The Company has assessed each of the eight specific presentation issues and the adoption of this ASU does not have a material impact on the consolidated financial statements.

Accounting for Credit Losses
ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. The Company is currently assessing the impact of the new standard on our consolidated financial statements. The accounting update is effective January 1, 2020.

Recognition of Leases
ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations. It requires lessees of operating lease arrangements to recognize lease assets and lease liabilities on the statement of financial position and disclose additional key information about lease agreements. The accounting update also replaces the current definition of a lease and requires that an arrangement be recognized as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. The Company is currently gathering a complete inventory of its lease contracts in order to assess the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2018 and is to be applied using a modified retrospective approach.

Recognition and Measurement of Financial Assets and Liabilities
ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation and disclosure of financial assets and liabilities. Investments in equity securities, excluding equity method and consolidated investments, are no longer classified as trading or available-for-sale securities. All investments in equity securities with readily determinable fair values are classified as investments at fair value through net income. Investments in equity securities without readily determinable fair values are measured using the fair value measurement alternative and are recorded at

cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the fair value measurement alternative are reviewed for indicators of impairment each reporting period. Fair value of financial instruments for disclosure purposes is measured using exit price. The accounting update is effective January 1, 2018 and will be applied on a prospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers
ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. It also requires the use of more estimates and judgments than the present standards in addition to additional disclosures. The new standard is effective January 1, 2018. The new standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. The Company has decided to adopt the new standard using the modified retrospective method.

The Company has reviewed its revenue contracts in order to evaluate the effect of the new standard on its revenue recognition practices. Based on the Company's assessment, the application of the standard will result in a change in presentation for payments to customers under an earnings sharing mechanism which are currently shown as an expense in the Consolidated Statements of Earnings. Under the new standard, these payments will be reflected as a reduction of revenue. The Company does not expect that these changes will have a material impact on revenue or earnings. The Company has also developed and tested processes to generate the disclosures which will be required under the new standard commencing in Q1 2018.

4. ASSETS HELD FOR SALE

In August 2017, the Company entered into an agreement to sell the issued and outstanding shares of St. Lawrence Gas for cash proceeds of approximately $88 million (US $70 million). Subject to regulatory approval and certain pre-closing conditions, the transaction is expected to close in 2018. As at December 31, 2017, St. Lawrence Gas was classified as held for sale and the related assets and liabilities were measured at the lower of their carrying value and fair value less costs to sell. Included within Assets held for sale, long-term is $94 million related to Property, plant and equipment, net. No impairment loss was recognized on the classification of St. Lawrence Gas as held for sale. Any gain or loss on the sale will be measured and recorded at the date that the transaction closes.

5. REGULATORY MATTERS

RATE APPROVALS
Enbridge Gas Distribution
For the year ended December 31, 2017, the Company's rates were set according to the OEB Decision and Rate Order (December 2016) in the Company's 2017 rate application. The rates approved as part of the 2017 rate application represented the fourth year of the Company's customized incentive regulation (IR) plan, which set rates for the period of 2014 to 2018, and was approved by the OEB in July and August 2014. The customized IR plan requires the Company to update select items in each of 2015 through 2018, in order to establish final allowed revenues and rates.

Effective January 1, 2017, in accordance with the OEB's Interim Rate Order (November 2016) in the Company's 2017 Cap and Trade Compliance Plan application, the Company also commenced charging customers interim cap and trade unit rates. The interim cap and trade unit rates were confirmed as final cap and trade unit rates, as per the OEB's Decision and Rate Order (November 2017) in the aforementioned application.

For the year ended December 31, 2016, the Company's rates were set according to the OEB approved settlement agreement (December 2015) in the Company's 2016 rate application, updated to reflect the OEB's decision and final rate order (May 2016) in the Company's multi-year demand side management (DSM) application.

Under the customized IR plan, the Company has continued to apply the accounting guidance found in Accounting Standards Codification (ASC) 980 - Regulated Operations.

St. Lawrence Gas

St. Lawrence Gas is currently in a rate year ending May 31, 2018, according to the recent NYSPSC order establishing a three year rate plan covering the period of June 1, 2016 through May 31, 2019. For the years ended December 31, 2017 and 2016, St. Lawrence Gas' rates were set using a Cost of Service (COS) methodology. Under COS, revenues are set to recover costs and to earn a rate of return on the deemed common equity component of rate base. Costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, interest and income taxes. Rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Gas costs are not recovered through revenue rates, but are set separately in gas cost rates.

The calculation of earnings sharing is on an annual basis for each rate year period commencing June 1, 2016. For the fiscal rate years ending May 31, 2018 and 2017, any earnings above the approved return on equity and between 9.5% to 10.0% will be shared 50/50 between customers and the Company; from 10.0% to 10.5%, 80/20; and over 10.5%, 90/10.

Under COS, it is the responsibility of St. Lawrence Gas to demonstrate to the NYSPSC the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken.

During the years ended December 31, 2017 and 2016, the cost of natural gas was passed on to customers as a flow-through.

APPROVED RETURNS ON EQUITY

Enbridge Gas Distribution

Enbridge Gas Distribution's rates for 2017 included an after-tax rate of return on common equity of 8.78% (2016 - 9.19%) based on a 36% (2016 - 36%) deemed common equity component of rate base.

St. Lawrence Gas

St. Lawrence Gas' approved after-tax rate of return on common equity embedded in rates was 9.0% for the rate year ended May 31, 2018 (fiscal 2016 - 9.0%) based on a 48% (fiscal 2016 - 48%) deemed common equity component of rate base.

FINANCIAL STATEMENT EFFECTS

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	**2017**	2016	Consolidated Statement of Financial Position Location
(millions of dollars)			
Current regulatory assets			
Purchase gas variance[1]	**55**	5	AR
Other current regulatory assets	**78**	61	AR
Total current regulatory assets	**133**	66	
Long-term regulatory assets			
Deferred income taxes[2]	**468**	381	DA
Pension plan receivable[3]	**42**	60	DA
OPEB[4]	**67**	71	DA
Other long-term regulatory assets	**18**	56	DA
Total long-term regulatory assets	**595**	568	
Total regulatory assets	**728**	634	
Current regulatory liabilities			
Site restoration clearance adjustment[5]	**31**	77	AP
Other regulatory liabilities	**45**	19	AP
Total current regulatory liabilities	**76**	96	
Long-term regulatory liabilities			
Future removal and site restoration reserves[6]	**603**	577	OLTL
Site restoration clearance adjustment[5]	**—**	32	OLTL
Other regulatory liabilities	**8**	15	OLTL
Total long-term regulatory liabilities	**611**	624	
Total regulatory liabilities	**687**	720	

AR – Accounts receivable and other
AP – Accounts payable and other
DA – Deferred amounts and other
OLTL – Other long-term liabilities

1 *Purchase gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates.*

2 *The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate regulation accounting, this regulatory balance and the related earnings impact would not be recorded.*

3 *The pension plan balance represents the regulatory offset to the pension liability to the extent the amounts are to be collected in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation accounting, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

4 *The OPEB balance represents the Company's right to recover OPEB costs resulting from the adoption of the accrual basis of accounting for OPEB costs upon transition to US GAAP in 2012. Pursuant to the OEB rate order, the amount as at December 31, 2012 is to be collected in rates over a 20-year period that commenced in 2013. In the absence of rate regulation accounting, this regulatory balance and related earnings impact would not be recorded.*

5 *The site restoration clearance adjustment represents the amount that was determined by the OEB of previously collected costs for future removal and site restoration that is now considered to be in excess of future requirements and will be refunded to customers over the customized IR term.*

6 *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment that is recorded in rates. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation accounting, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Operating Cost Capitalization

In the absence of rate regulation accounting, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred.

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation accounting, a portion of such operating costs would be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2017, the net book value of these costs included in gas mains in Property, plant and equipment, net was $118 million (2016 - $125 million). In the absence of rate regulation accounting, some of these costs would be charged to earnings in the year incurred.

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2017, the net book value of these costs included in intangible assets was $22 million (2016 - $35 million). In the absence of rate regulation accounting, a portion of the original cost of these assets would have been expensed in the period incurred.

WAMS is the Company’s new integrated work and asset management solution. At December 31, 2017, the net book value of the asset included in intangible assets was $77 million (2016 - $84 million). In the absence of rate regulation accounting, a portion of the original cost of the asset would have been expensed in the period incurred.

Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers’ system supply rates. Included in gas inventories at December 31, 2017 is $55 million (2016 - $49 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation accounting, these costs would be expensed as incurred and inventory would be recorded at the lower of cost or market value.

Depreciation

In the absence of rate regulation accounting, depreciation rates would not have included a charge for future removal and site restoration costs.

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2017**	2016
(millions of dollars)		
Trade receivables	**373**	327
Unbilled revenues	**209**	135
Regulatory assets *(Note 5)*	**133**	66
Other	**163**	160
Allowance for doubtful accounts *(Note 14)*	**(29)**	(33)
	849	655

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2017**	2016
(millions of dollars)			
Regulated property, plant and equipment			
Gas mains	**2.2%**	**4,717**	4,637
Gas services	**2.3%**	**3,157**	3,065
Regulating and metering equipment	**5.2%**	**1,012**	963
Gas storage	**1.9%**	**379**	366
Right-of-way	**1.2%**	**112**	106
Computer technology	**32.6%**	**30**	33
Under construction	**—**	**109**	130
Construction materials inventory	**—**	**37**	34
Land	**—**	**28**	28
Other	**6.8%**	**298**	300
		9,879	9,662
Accumulated depreciation		**(2,435)**	(2,334)
		7,444	7,328
Unregulated property, plant and equipment			
Gas storage	**1.9%**	**89**	90
Other	**0.5%**	**18**	23
		107	113
Accumulated depreciation		**(19)**	(23)
		88	90
Property, plant and equipment, net		**7,532**	7,418

Depreciation expense, including amounts collected for future removal and site restoration costs, was $268 million for the year ended December 31, 2017 (2016 - $266 million).

The Company incurred approximately $15 million for the year ended December 31, 2017 (2016 - $15 million) in incremental depreciation resulting from push-down accounting *(Note 2)*.

8. INTANGIBLE ASSETS

December 31,	2017	2016
(millions of dollars)		
Intangible assets	**779**	**406**
Less: Accumulated amortization	**(293)**	**(248)**
Intangible assets, net	**486**	**158**

Intangible assets consists of software, CIS, and emission allowances. Beginning January 1, 2017, emission allowances were purchased by the Company for itself and most of its customers in order to meet greenhouse gas compliance obligations in the Province of Ontario. Purchased emission allowances are recorded at their original cost and are not amortized, as they will be used to satisfy compliance obligations as they come due. For the year ended December 31, 2017, the weighted average amortization rate for software and CIS were 18.8% and 10.0% respectively (2016 - 22.2% and 10.0% respectively).

Intangible assets include $15 million of work-in-progress as at December 31, 2017 (2016 - $12 million). Total amortization expense for intangible assets was $62 million for the year ended December 31, 2017 (2016 - $56 million). The Company expects aggregate amortization expense for the years ending

December 31, 2018 through 2022 of $68 million, $59 million, $62 million, $64 million and $65 million, respectively.

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2017**	2016
(millions of dollars)		
Accrued liabilities	**325**	371
Trade payables	**94**	82
Regulatory liabilities *(Note 5)*	**76**	96
Other	**167**	258
	662	807

10. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2017**	2016
(millions of dollars)				
Debenture	9.85%	2024	**85**	85
Medium-term notes[1]	4.47%	2020-2050	**3,695**	3,895
Commercial paper and credit facility draws, net			**960**	360
Other[2]			**(20)**	15
Total debt			**4,720**	4,355
Current maturities			**—**	(500)
Short-term borrowings	1.43%		**(960)**	(351)
Short-term borrowings from affiliates[3] *(Note 18)*			**—**	(34)
Long-term debt			**3,760**	3,470
Loans from affiliate company *(Note 18)*			**375**	375

1 The balance in 2017 pertaining to St. Lawrence Gas amounting to approximately $9 million is presented as Liabilities held for sale, long-term (Note 4) on the Consolidated Statements of Financial Position.
2 Consists of note payable to affiliate company, debt premium and/or debt issuance costs.
3 The balance in 2017 pertaining to St. Lawrence Gas amounting to approximately $30 million is presented as Liabilities held for sale, current (Note 4) on the Consolidated Statements of Financial Position.

In November 2017, the Company issued $300 million of thirty-year medium-term notes (MTNs) at an interest rate of 3.51% payable semi-annually in arrears. This MTN matures in November 2047.

In August 2016, the Company issued $300 million of ten-year MTNs at an interest rate of 2.50% payable semi-annually in arrears. This MTN matures in August 2026.

For the years ending December 31, 2018 through 2022, medium-term note maturities are nil, nil, $400 million, $175 million and nil, respectively. The Company's debentures and medium-term notes bear interest at fixed rates, and interest obligations for the years ending December 31, 2018 through 2022 are $174 million, $174 million, $174 million, $157 million and $149 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2017**	2016
(millions of dollars)		
Debentures and medium-term notes	**176**	176
Loans from affiliate company *(Note 18)*	**28**	27
Commercial paper and credit facility draws	**8**	7
Other interest and finance costs	**7**	10
Capitalized	**(5)**	(14)
	214	206

In 2017, total interest paid to third parties was $185 million (2016 - $181 million) and total interest paid to affiliates was $28 million (2016 - $27 million).

The Company's borrowings, whether debentures or MTNs, are unsecured. As at December 31, 2017, the Company was in compliance with all covenants.

CREDIT FACILITIES

The Company currently has a $1 billion commercial paper program limit that is backstopped by committed lines of credit of $1 billion. The term of any commercial paper issued under this program may not exceed one year. The maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option. In July 2017, the Company extended the term out date of this external credit facility to July 2018, with a maturity date in July 2019.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2017.

			December 31, 2017		December 31, 2016
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of dollars)					
Enbridge Gas Distribution Inc.	2019	**1,000**	**960**	**40**	1,000
St. Lawrence Gas Company, Inc.	2019	**16**	**12**	**4**	17
Total credit facilities		**1,016**	**972**	**44**	1,017

1 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the external credit facility. St. Lawrence Gas draws are shown as Liabilities held for sale, current and long-term on the Consolidated Statements of Financial Position.

Credit facilities carried a weighted average standby fee of 0.2% on the unused portion and the draws bear interest at market rates.

11. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preference shares.

COMMON SHARES

	2017		2016	
December 31,	Number of shares	Amount	Number of shares	Amount
(millions of dollars; number of common shares in millions)				
Balance at beginning of year	**185.6**	**1,917**	170.0	1,637
Common shares issued	**27.7**	**500**	15.6	280
Balance at end of year *(Note 18)*	**213.3**	**2,417**	185.6	1,917

PREFERENCE SHARES

December 31, 2017 and 2016	Authorized	Issued and Outstanding	Amount
(millions of dollars, number of preference shares in millions)			
Group 2, Series A - C, Cumulative Redeemable Retractable	6	—	—
Group 2, Series D, Cumulative Redeemable Convertible	4	—	—
Group 3, Series A - C, Cumulative Redeemable Retractable	6	—	—
Group 3, Series D, Fixed / Floating Cumulative Redeemable	4	4	100
Group 4	10	—	—
Group 5	10	—	—
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preference shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case. As at December 31, 2017, no preference shares have been redeemed.

On July 1, 2019, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference shares on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preference shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder's option on July 1, 2019 and every five years thereafter.

12. STOCK OPTION AND STOCK UNIT PLANS

Enbridge's four long-term incentive compensation plans include the ISO Plan, the PSO Plan, the PSU Plan and the RSU Plan. The Company reimburses Enbridge for stock-based compensation costs associated with its employees on a quarterly basis. As at December 31, 2017, the Company did not have any employees that had options in the PSO Plan.

INCENTIVE STOCK OPTIONS
(options in thousands)
Key employees of the Company are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

Compensation expense recorded for the year ended December 31, 2017 for ISOs was $5 million (2016 - $6 million). At December 31, 2017, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $2 million. The cost is expected to be fully recognized over a weighted average period of approximately three years. As at December 31, 2017, there were 2,838 ISOs outstanding (2016 - 3,476 ISOs outstanding).

PERFORMANCE STOCK UNITS
(units in thousands)
Enbridge has a PSU Plan for senior officers of the Company where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two if Enbridge performs within the highest range of its performance targets. The performance multiplier is derived through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's earnings per share, adjusted for unusual non-operating or non-recurring items, relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2017 for PSUs was nil (2016 - $4 million). As at December 31, 2017, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $1 million and is expected to be fully recognized over a weighted average period of approximately two years. As at December 31, 2017, there were 19 PSUs outstanding (2016 - 35 PSUs outstanding).

RESTRICTED STOCK UNITS
(units in thousands)
Enbridge has a RSU Plan where cash awards are paid to certain non-executive employees of the Company following a 35-month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

Compensation expense recorded for the year ended December 31, 2017 for RSUs was $5 million (2016 - $6 million). As at December 31, 2017, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $5 million and is expected to be fully recognized over a weighted average period of approximately two years. As at December 31, 2017, there were 165 RSUs outstanding (2016 - 187 RSUs outstanding).

13. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

Changes in AOCI for the years ended December 31, 2017 and 2016 are as follows:

	2017			
	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of dollars)				
Balance at January 1, 2017	**(11)**	**4**	**(8)**	**(15)**
Other comprehensive loss retained in AOCI	**—**	**(2)**	**(2)**	**(4)**
Other comprehensive loss reclassified to earnings	**4**	**—**	**—**	**4**
	(7)	**2**	**(10)**	**(15)**
Tax Impact				
Income tax on amounts retained in AOCI	**(1)**	**—**	**—**	**(1)**
Income tax on amounts reclassified to earnings	**—**	**—**	**—**	**—**
	(1)	**—**	**—**	**(1)**
Balance at December 31, 2017	**(8)**	**2**	**(10)**	**(16)**

	2016			
	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of dollars)				
Balance at January 1, 2016	(5)	6	(7)	(6)
Other comprehensive income/(loss) retained in AOCI	(14)	(2)	(2)	(18)
Other comprehensive loss reclassified to earnings	6	—	—	6
	(13)	4	(9)	(18)
Tax Impact				
Income tax on amounts retained in AOCI	3	—	—	3
Income tax on amounts reclassified to earnings	(1)	—	1	—
	2	—	1	3
Balance at December 31, 2016	(11)	4	(8)	(15)

14. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in natural gas prices, emission allowance prices, foreign exchange rates and interest rates (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them.

Natural Gas Price Risk
Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customers; therefore, the net exposure to the Company is zero.

Emission Allowance Price Risk
Emission allowance price risk is the risk of gain or loss due to changes in the market price of emission allowances that the Company is required to purchase for itself and most of its customers to meet greenhouse gas compliance obligations under the Ontario Cap and Trade framework. Similar to the gas supply procurement framework, the OEB's framework for emission allowance procurement allows recovery of fluctuations in emission allowance prices in customer rates, subject to OEB approval.

Foreign Exchange Risk
Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. The Company generates certain revenues, and holds a subsidiary that is denominated in United States dollars (USD). As a result, the Company's earnings, cash flows, and OCI are exposed to fluctuations resulting from USD exchange rate variability.

The Company implemented a policy in 2016 to hedge a portion of USD denominated unregulated storage revenue exposures. Qualifying derivative instruments were used to hedge anticipated USD denominated revenues and to manage variability in cash flows through September 2017. During September 2017, the Company assigned its USD denominated unregulated storage contracts to Union Gas Limited (Union Gas), an affiliated company under common control as a result of the merger transaction *(Note 18)*. The Company has also novated all of its qualifying derivative instruments relating to forward exchange contracts to Union Gas.

A portion of the Company's purchases of natural gas are denominated in USD and as a result there is exposure to fluctuations in the exchange rate of the USD against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the Company has no net exposure to movements in the foreign exchange rate on natural gas purchases.

Interest Rate Risk
The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps were used through January 2017 to mitigate the volatility of short-term interest rates on interest expense related to variable rate debt.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps were used during 2016 to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances.

The Company's portfolio mix of fixed and variable rate debt instruments is monitored by its ultimate parent company, Enbridge. The Company does not typically manage the fair value of its debt instruments.

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the financial statement line item in the Consolidated Statements of Financial Position and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges or net investment hedges at December 31, 2017 or December 31, 2016.

The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2017	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of dollars)					
Other long-term liabilities					
Foreign exchange contracts	—	—	—	—	—
Total net derivative liabilities					
Foreign exchange contracts	—	—	—	—	—

December 31, 2016	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of dollars)					
Other long-term liabilities					
Foreign exchange contracts	(1)	—	(1)	—	(1)
Total net derivative liabilities					
Foreign exchange contracts	(1)	—	(1)	—	(1)

The Company did not have any outstanding derivative instruments relating to interest rate contracts as at December 31, 2017. Derivative instruments relating to interest rate contracts as at December 31, 2016 had a notional principal of $8 million for interest rate contracts for short-term borrowings and zero for interest rate contracts on the anticipated issuance of long-term debt.

The Company did not have any outstanding derivative instruments relating to forward exchange contracts as at December 31, 2017. At December 31, 2016 the Company's derivative instruments relating to foreign exchange forward contracts matured through 2023 and had a notional principal of $13 million (US $10 million).

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2017**	2016
(millions of dollars)		
Amount of unrealized loss recognized in OCI cash flow hedges		
Interest rate contracts	—	(13)
Foreign exchange contracts	—	(1)
	—	(14)
Amount of loss reclassified from AOCI to earnings *(effective portion)*		
Interest rate contracts[1]	**(4)**	(3)
	(4)	(3)
Amount of loss reclassified from AOCI to earnings *(ineffective portion)*		
Interest rate contracts[1]	—	(3)
	—	(3)

1 Reported within Interest expense in the Consolidated Statements of Earnings.

The Company estimates that no amount in AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on interest and foreign exchange rates in effect when derivative contracts that are currently outstanding mature.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under committed credit facilities and long-term debt, which includes debentures and medium term notes (MTNs) and, if necessary, additional liquidity is available through intercompany transactions with its ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable the Company to fund all anticipated requirements. The Company also maintains committed credit facilities with a diversified group of banks and institutions. The Company is in compliance with all the terms and conditions of its committed credit facilities as at December 31, 2017. As a result, all credit facilities are available to the Company and the banks are obligated to fund the Company under the terms of the facilities.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts, which totaled $29 million at December 31, 2017 (December 31, 2016 - $33 million).

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate.

Entering into derivative financial instruments may also result in exposure to credit risk. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

The Company did not have group credit concentrations, with respect to derivative instruments, in the Canadian, United States, European, Asian or other financial institutions counterparty segments at December 31, 2017 or December 31, 2016.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company categorizes its derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company does not have any derivative instruments classified as Level 1.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps for which observable inputs can be obtained.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support a Level 2 classification. The

Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2017, the Company had Level 2 derivative assets with fair value of nil (2016 - nil) and Level 2 derivative liabilities with fair value of nil (2016 - $1 million). The Company’s policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers between levels as at December 31, 2017 or December 31, 2016.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted market prices are not available for fair value measurement in which case these investments are recorded at cost. The Company’s investment in IPL System Inc., an affiliate company, is recorded at fair value. At December 31, 2017, the fair value of the investment was $825 million (2016 - $825 million). The fair value of the Company’s investment is classified as a Level 2 measurement and as at December 31, 2017 and 2016 the fair value approximated its cost and redemption value and therefore no amount was recognized in OCI.

The fair value of the Company’s long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2017, the Company’s long-term debt, including the current portion had a carrying value of $3,780 million (2016 - $3,983 million) before debt issue costs and a fair value of $4,363 million (2016 - $4,585 million).

The fair value of other financial assets and liabilities other than derivative instruments and long-term debt approximate their cost due to the short period to maturity.

15. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2017**	2016
(millions of dollars)		
Earnings before income taxes	**236**	239
Federal statutory income tax rate	**15.0 %**	15.0%
Federal income taxes at statutory rate	**35**	36
Increase/(decrease) resulting from:		
Provincial and state income taxes	**(11)**	(27)
Effects of rate regulated accounting[1,2]	**(36)**	(25)
Non-taxable intercompany distributions[2]	**(9)**	(9)
Part VI.1 tax, net of federal Part I tax deduction[2]	**—**	35
Investment in foreign subsidiaries held for sale *(Note 4)*	**4**	—
Other[3]	**3**	(1)
Income tax expense/(recovery)	**(14)**	9
Effective income tax rate	**(5.9)%**	3.8%

1 During 2017, 2016, 2015 and 2014, previously collected costs for future removal and site restoration were refunded to customers that resulted in a decrease in income taxes of $21 million at December 31, 2017 (2016 - $22 million).
2 The provincial tax component of these items is included in “Provincial and state income taxes” above.
3 Included in “Other” are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals & entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2017**	2016
(millions of dollars)		
Earnings before income taxes		
Canada	**232**	236
United States	**4**	3
	236	239
Current income taxes		
Canada	**5**	32
United States	**—**	(1)
	5	31
Deferred income taxes		
Canada	**(20)**	(24)
United States	**1**	2
	(19)	(22)
Income tax expense/(recovery)	**(14)**	9

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2017**	2016
(millions of dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(662)**	(637)
Regulatory assets	**(124)**	(101)
Deferrals	**(24)**	(8)
Other	**(4)**	—
Total deferred income tax liabilities	**(814)**	(746)
Deferred income tax assets		
Future removal and site restoration reserves	**160**	153
Retirement and postretirement benefits	**31**	37
Minimum tax credits	**12**	13
Loss carryforwards	**13**	4
Financial derivatives	**3**	4
Other	**4**	3
Total deferred income tax assets	**223**	214
Net deferred income tax liabilities	**(591)**	(532)

In 2017, the investment in St. Lawrence Gas was classified as held for sale. The Company is no longer asserting permanent reinvestment for this foreign subsidiary's earnings. As such, it recorded a deferred tax liability of $4 million on the difference between the carrying value of this foreign subsidiary and its corresponding tax basis. This difference is largely a result of unremitted earnings and currency translation adjustments.

In 2016, the Company did not provide for deferred taxes on this difference as the earnings in this subsidiary were intended to be permanently reinvested in its operations. As such, this investment was not anticipated to give rise to income taxes in the foreseeable future. The unremitted earnings and currency translation adjustment for which no deferred taxes were provided in 2016 was $30 million.

The Company and its subsidiaries are subject to taxation in Canada and the Unites States. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario). The Company is open to examination by Canadian tax authorities for the 2012 to 2017 tax years. The Company is currently under examination for income tax matters in Canada for the 2015 to 2016 tax years.

UNRECOGNIZED TAX BENEFITS

The Company has no unrecognized tax benefits related to uncertain tax positions as at December 31, 2017 and 2016 and no accrued interest or penalties thereon.

16. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

Substantially all of the Company's employees participate in non-contributory pension plans which provide defined benefit and/or defined contribution pension benefits. The Company also maintains supplemental pension plans that provide pension benefits in excess of the basic plan for certain employees.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on each plan participant's years of service and final average remuneration. These benefits are partially inflation-indexed after a plan participant's retirement. The Company's contributions are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities.

Defined Contribution Plans
Contributions are generally based on each plan participant's age, years of service and current eligible remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

OTHER POSTRETIREMENT BENEFITS
OPEB primarily includes supplemental health and dental, health spending accounts and life insurance coverage for qualifying retired employees on a non-contributory basis.

BENEFIT OBLIGATIONS AND FUNDED STATUS
The following table details the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans.

	Pension		OPEB	
December 31,	**2017**	2016	**2017**	2016
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,098**	1,025	**123**	120
Service cost	**33**	32	**2**	1
Interest cost	**36**	35	**4**	5
Actuarial loss	**43**	51	**1**	2
Benefits paid	**(58)**	(46)	**(4)**	(4)
Other	**(16)**	1	**(14)**	(1)
Benefit obligation at end of year[1]	**1,136**	**1,098**	**112**	**123**
Change in plan assets				
Fair value of plan assets at beginning of year	**998**	969	**17**	17
Actual return on plan assets	**107**	73	**2**	1
Employer's contributions	**47**	1	**4**	5
Benefits paid	**(58)**	(46)	**(4)**	(4)
Other	**(7)**	1	**(19)**	(2)
Fair value of plan assets at end of year	**1,087**	**998**	**—**	**17**
Underfunded status at end of year	**(49)**	**(100)**	**(112)**	**(106)**
Presented as follows:				
Deferred amounts and other assets	**2**	3	**—**	3
Accounts payable and other *(Note 9)*	**—**	—	**(4)**	(4)
Other long-term liabilities	**(51)**	(103)	**(108)**	(105)

1 For pension plans, the benefit obligation is the projected obligation. For OPEB plans, the benefit obligations is the accumulated postretirement benefit obligation. The accumulated benefit obligation for the Company's pension plans was $1,051 million as at December 31, 2017 (2016 - $991 million).

At December 31, 2017, pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations of $54 million (2016 - $106 million), accumulated benefit obligations of $1,109 million (2016 - $1,072 million) and plan assets with a fair value of $1,055 million (2016 - $966 million).

AMOUNTS RECOGNIZED IN OTHER COMPREHENSIVE INCOME
The net actuarial loss included in AOCI, before tax, was $12 million relating to the Company's OPEB plans as at December 31, 2017 (2016 - $11 million).

NET BENEFIT COST RECOGNIZED

The components of net benefit cost and other amounts recognized in pre-tax OCI related to the Company's pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2017**	2016	**2017**	2016
(millions of Canadian dollars)				
Service cost	**33**	32	**2**	1
Interest cost	**36**	35	**4**	5
Expected return on plan assets	**(63)**	(60)	**(1)**	(1)
Amortization of actuarial loss	**17**	14	**—**	—
Net defined benefit and OPEB costs	**23**	21	**5**	5
Defined contribution benefit costs	**1**	1	**—**	—
Net benefit cost recognized in Earnings	**24**	**22**	**5**	**5**
Amount recognized in OCI				
Net actuarial loss arising during the year	**—**	—	**2**	2
Total amount recognized in OCI	**—**	—	**2**	2
Total amount recognized in Comprehensive income	**24**	22	**7**	7

The Company estimates that approximately $14 million related to pension plans and OPEB plans as at December 31, 2017 will be reclassified from AOCI into earnings in the next 12 months.

Pension and OPEB costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension and OPEB costs due to the regulatory mechanism in place. As a result, the net pension and OPEB expense primarily consists of OEB approved pension and OPEB costs.

Regulatory adjustments were recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers, respectively, in future rates *(Note 5)*. For the year ended December 31, 2017 there were nominal differences between pension expense for accounting purposes and pension expense for ratemaking purposes. For the year ended December 31, 2016, an offsetting regulatory liability increased by $10 million and has been recorded to the extent pension and OPEB costs are expected to be refunded to customers in future rates.

ACTUARIAL ASSUMPTIONS

The weighted average assumptions made in the measurement of the benefit obligations and net benefit cost of the Company's pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2017**	2016	**2017**	2016
Benefit obligations				
Discount rate	**3.6%**	3.9%	**3.6%**	3.9%
Rate of salary increase	**3.2%**	3.5%	**3.2%**	3.5%
Net benefit cost				
Discount rate - service cost	**4.1%**	4.3%	**4.1%**	4.3%
Discount rate - interest cost	**3.9%**	3.5%	**4.0%**	3.5%
Rate of return on plan assets	**6.4%**	6.5%	**0.0%**	6.0%
Rate of salary increase	**3.5%**	3.4%	**3.5%**	3.4%

The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

ASSUMED HEALTH CARE COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	2017	2016
Health care cost trend rate assumed for next year	**5.5%**	5.6%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	**4.3%**	4.3%
Year that the rate reaches the ultimate trend rate	**2034**	2034

A 1% point change in the assumed health care cost trend rate would have the following effects for the year ended and as at December 31, 2017:

	1% Point Increase	1% Point Decrease
(in millions of dollars)		
Effect on total service and interest costs	—	—
Effect on accumulated postretirement benefit obligation	14	(11)

PLAN ASSETS

The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the Company’s operating environment and financial situation and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The asset allocation targets and major categories of plan assets are as follows:

Asset Category	Target Allocation	December 31, 2017	2016
Equity securities	46-70%	**48.5%**	47.0%
Fixed income securities	30-36%	**34.0%**	36.0%
Other	0-18%	**17.5%**	17.0%

The following table summarizes the fair value of the plan assets for the Company's pension and OPEB plans recorded at each fair value hierarchy level.

	2017				2016			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension Benefits								
Cash and cash equivalents	**15**	**—**	**—**	**15**	7	—	—	7
Equity securities								—
United Stated	**208**	**—**	**—**	**208**	110	—	—	110
Canada	**228**	**—**	**—**	**228**	209	—	—	209
Global	**85**		**—**	**85**	74	72	—	146
Fixed income securities								—
Government	**225**	**—**	**—**	**225**	204	—	—	204
Corporate	**141**	**—**	**—**	**141**	145	—	—	145
Infrastructure and real estate	**—**	**—**	**178**	**178**	—	—	153	153
Forward currency contracts	**—**	**(5)**	**—**	**(5)**	—	—	—	—
	902	**(5)**	**178**	**1,075**	749	72	153	974
Non-financial instruments	**—**	**—**	**—**	**12**	—	—	—	24
Total pension plan assets at fair value				**1,087**				**998**
OPEB								
Equity securities								
United States	**—**	**—**	**—**	**—**	5	—	—	5
Global	**—**	**—**	**—**	**—**	5	—	—	5
Fixed income securities								—
Government	**—**	**—**	**—**	**—**	7	—	—	7
Total OPEB plan assets at fair value	**—**	**—**	**—**	**—**	**17**	—	—	17

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair values of the infrastructure and real estate investments are established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2017**	2016
(millions of dollars)		
Balance at beginning of year	**153**	147
Unrealized and realized gains	**17**	13
Purchases and settlements, net	**8**	(7)
Balance at end of year	**178**	153

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2018	2019	2020	2021	2022	2023- 2027
(millions of Canadian dollars)						
Pension	50	52	53	55	57	307
OPEB	5	5	5	5	4	26

17. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2017**	2016
(millions of dollars)		
Restricted cash	**15**	(58)
Accounts receivable and other[1,2]	**(169)**	(39)
Gas inventory	**20**	35
Regulatory assets *(Note 5)*	**(7)**	158
Deferred amounts and other assets[1]	**(34)**	—
Accounts payable and other[1,2]	**(61)**	109
Regulatory liabilities *(Note 5)*	**(102)**	(127)
Cap and trade compliance liability[3]	**365**	—
	27	78

1 *The cash flow impacts of regulatory assets and liabilities have been separately disclosed and are not included.*
2 *Includes amounts related to affiliated companies.*
3 *Under cap and trade regulation in the Province of Ontario, the Company is required to meet greenhouse gas compliance obligations for most of its customers' use of natural gas as well as emissions from its own operations. The Company will be required to relieve its compliance liability, through the submission of emission allowances, following the completion of the initial compliance period of January 1, 2017 through December 31, 2020. The balance in 2017 is presented as Other long-term liabilities on the Consolidated Statements of Financial Position.*

18. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Year ended December 31,	**2017**	2016
(millions of dollars)		
Enbridge Energy Distribution Inc.		
Common share dividends declared	**600**	237
Union Gas[1]		
Purchase of gas storage and transportation services	**112**	—
Revenue from unregulated storage capacity	**5**	—
IPL System Inc.		
Dividend income	**63**	63
Interest expense (Note 10)	**27**	27
Enbridge		
Purchase of treasury and other management services	**49**	49
Part VI.1 tax reimbursement (Note 15)	**—**	5
Tidal Energy Marketing Inc.		
Purchase of natural gas	**54**	24
Revenue from optimization services	**9**	8
Revenue from unregulated storage capacity	**2**	2
Tidal Energy Marketing (U.S.) LLC		
Purchase of natural gas	**56**	26
Aux Sable Canada LP		
Purchase of natural gas	**—**	16
Gazifère Inc.		
Revenue from wholesale service, including gas sales	**30**	30
Other related entities		
Purchase of gas transportation services	**25**	31

1 *On February 27, 2017, Enbridge and Spectra Energy Corp. (Spectra) combined, to complete a merger transaction. The Company purchases gas storage and transportation services from Union Gas, an indirectly wholly owned subsidiary of Spectra, at prevailing market prices and under normal trade terms. The purchase of gas storage and transportation services and revenue from unregulated storage capacity from Union Gas includes only 10 months of activity subsequent to the merger transaction.*

The Company had related party balances as follows:

December 31,	**2017**	2016
(millions of dollars)		
Common share ownership from parent company		
Enbridge Energy Distribution Inc.	**2,417**	1,917
Dividend payable	**—**	59
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**9**	2
Note payable to affiliate company		
Enbridge (U.S.) Inc.	30	34
Other accounts receivable/(payable)		
Other related entities, net	**(40)**	(23)

Financing Transactions
The Company has invested in Class D, non-voting, redeemable, retractable preference shares of IPL System Inc., an affiliate under common control. At December 31, 2017, the investment of $825 million (2016 - $825 million) in these shares resulted in a weighted average dividend yield of 7.6%.

At December 31, 2017, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.9% and $175 million at 7.5%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preference shares of the Company. For the year ended December 31, 2017, interest paid amounted to $27 million (2016 - $27 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 1.1% and is payable on demand.

Treasury and Other Management Services
Enbridge provides treasury and other management services and charges the Company on a cost recovery basis.

Part VI.1 Tax Reimbursement
The Company entered into an agreement with Enbridge for the transfer of Part VI.1 tax and the related Part I tax deduction. The Company received a non-taxable reimbursement relating to the transfer.

Natural Gas Purchases
The Company contracted for the purchase of natural gas from Aux Sable Canada LP, Tidal Energy Marketing Inc. and Tidal Energy Marketing (U.S.) LLC, related entities under common control, at prevailing market prices under normal trade terms. Contractual obligations under the Tidal Energy Marketing (U.S.) LLC and Tidal Energy Marketing Inc. contracts are 2018 to 2019 - $32 million, 2020 to 2021 - nil, and thereafter - nil.

Optimization Services
The Company provides pipeline and storage optimization services to Tidal Energy Marketing Inc., an affiliated entity under common control.

Wholesale Service
These gas procurement and transportation services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Storage and Transportation Services
The Company contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control, Niagara Gas Transmission Limited, 2193914 Canada Limited and Union Gas. The Company also contracted for natural gas storage services from Union Gas. Contractual obligations under the Union Gas, Vector Pipeline Limited Partnership (U.S.) and Vector Pipeline Limited Partnership (Canadian) are 2018 to 2019 - $316 million, 2020 to 2021 - $280 million and thereafter - $358 million.

Unregulated Storage Services
On July 31, 2017, the Company entered into a Gas Storage Service Agreement (GSSA) with Union Gas, whereby Union Gas contracted all of the Company's unregulated storage space and deliverability effective September 2017.

Trade Receivables and Payables
The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other shared corporate services to affiliates on a fully-allocated cost basis. Market prices, if they are reasonably determinable, are charged for affiliate services that are not shared corporate services. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company.

Other Transactions
The Company and affiliates invoice on a monthly basis and amounts are due and paid on a monthly basis.

19. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
At December 31, 2017, the Company had commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of dollars)							
Purchase of services, pipe and other materials, including transportation[1,2]	4,954	1,073	841	614	489	435	1,502

1 *Includes capital and operating commitments.*

2 *Included in these amounts are right-of-way payments, estimated to be approximately $2 million per year, related to cancellable gas storage lease payments that are reasonably likely to occur over the remaining life of all storage reservoirs, which have been assumed to be 65 years.*

The Company and certain affiliates, in aggregate, have access to $500 million of letters of credit that they can issue. The total outstanding letters of credit that related to the Company as at December 31, 2017 was $6 million.

ENVIRONMENTAL
The Company subject to various federal, state and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on the Company.

Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and the Company and its affiliates are, at times, subject to environmental remediation at various contaminated sites. The Company manages this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that the Company is unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, the Company will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of the Company.

Former Manufactured Coal Gas Plant Sites
The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

In its fiscal 2003 Rate Case, the Company sought OEB approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with a then current MGP claim and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2017 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

OTHER LITIGATION

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a significant impact on the Company's consolidated financial position or results of operations.

The Consolidated Financial Statements and all information in this report have been prepared by and are the responsibility of management. The Consolidated Financial Statements have been prepared in conformity with generally accepted accounting principles in the United States and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon Union Gas' system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors is responsible for ensuring that management fulfils its responsibility for financial reporting and for final approval of the Consolidated Financial Statements.

The Board of Directors meets regularly with management, the internal auditors and the shareholders' auditors to review the Consolidated Financial Statements, the Independent Auditor's Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Board of Directors, as does the Director of Internal Audit Services.

Deloitte LLP performed an independent audit of the 2012 and 2011 Consolidated Financial Statements in this report. Their independent professional opinion on the fairness of these Consolidated Financial Statements is included in the Independent Auditor's Report.

March 8, 2013

J. Patrick Reddy

Stephen W. Baker
President

J. Patrick Reddy
Chief Financial Officer

Deloitte LLP
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Canada

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Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying consolidated financial statements of Union Gas Limited, which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011, and the consolidated statements of operations and comprehensive income, equity, and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2012 and December 31, 2011 and the results of its operations and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Deloitte LLP

Chartered Accountants
Licensed Public Accountants
March 8, 2013

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the Years Ended December 31 ($millions)	**2012**	2011 (note 2)
Gas sales and distribution revenue	**1,365**	1,468
Cost of gas (note 14)	**638**	755
Gas distribution margin	**727**	713
Storage and transportation revenue (note 14)	**269**	311
Other revenue	**28**	34
	1,024	1,058
Expenses		
Operating and maintenance (note 14)	**380**	379
Depreciation and amortization	**213**	205
Property and other taxes	**65**	62
	658	646
Income before interest and income taxes	**366**	412
Interest expense (notes 7 and 14)	**156**	153
Income before income taxes	**210**	259
Income taxes (note 13)	**40**	58
Net income	**170**	201
Preferred stock dividends	**3**	2
Net income applicable to common stock	**167**	199
Other comprehensive income (loss), net of tax		
Pension and benefits impact (note 12)	**19**	(83)
Comprehensive income applicable to common stock	**186**	116

(*See accompanying notes)*

CONSOLIDATED STATEMENTS OF EQUITY

($millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total
December 31, 2011 (note 2)	627	764	(272)	9	1,128
Net income	–	170	–	–	170
Other comprehensive income	–	–	19	–	19
Dividends					
Preferred stock	–	(3)	–	–	(3)
Common stock	–	(162)	–	–	(162)
December 31, 2012	627	769	(253)	9	1,152
December 31, 2010 (note 2)	627	710	(189)	9	1,157
Net income	–	201	–	–	201
Other comprehensive loss	–	–	(83)	–	(83)
Dividends					
Preferred stock	–	(2)	–	–	(2)
Common stock	–	(145)	–	–	(145)
December 31, 2011	627	764	(272)	9	1,128

(*See accompanying notes)*

CONSOLIDATED BALANCE SHEETS

As at December 31 ($millions)	**2012**	2011 (note 2)
Assets		
Current assets		
Cash and cash equivalents	**9**	7
Accounts receivable, net (notes 4 and 14)	**588**	536
Inventories (note 5)	**199**	263
Deferred income taxes (note 13)	**14**	8
Total current assets	**810**	814
Property, plant and equipment (note 6)		
Cost	**6,803**	6,615
Accumulated depreciation	**2,236**	2,120
Property, plant and equipment, net	**4,567**	4,495
Regulatory and other assets (note 12)	**406**	355
Total Assets	**5,783**	5,664
Liabilities and Equity		
Current liabilities		
Short-term borrowings (note 14)	**9**	99
Commercial paper (note 7)	**374**	279
Accounts payable and accrued charges (notes 4 and 14)	**685**	622
Income taxes payable (note 13)	**26**	26
Total current liabilities	**1,094**	1,026
Long-term liabilities		
Long-term debt (note 7)	**2,287**	2,287
Deferred income taxes (note 13)	**352**	293
Asset retirement obligations (note 9)	**143**	134
Regulatory and other liabilities (note 12)	**645**	686
Total long-term liabilities	**3,427**	3,400
Total Liabilities	**4,521**	4,426
Preferred stock (note 8)	**110**	110
Equity		
Common stock,		
Unlimited shares authorized, 57,822,650 outstanding	**627**	627
Retained earnings	**769**	764
Accumulated other comprehensive loss	**(253)**	(272)
Non-controlling interest	**9**	9
Total Equity	**1,152**	1,128
Total Liabilities and Equity	**5,783**	5,664

(See accompanying notes)

Approved by the Board

Director

Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31 ($millions)	**2012**	2011 (note 2)
Operating Activities		
Net income	**170**	201
Items not affecting cash		
Depreciation and amortization	**213**	205
Deferred income taxes	**(8)**	8
Changes in working capital		
Accounts receivable	**(6)**	(15)
Inventories	**49**	(85)
Account payables, accrued charges and other	**15**	45
	433	359
Investing Activities		
Capital expenditures	**(271)**	(290)
Financing Activities		
Net decrease in short-term borrowings	**(90)**	(99)
Net increase in commercial paper	**95**	122
Long-term debt issued	–	300
Long-term debt repayment	–	(250)
Dividends paid	**(165)**	(147)
	(160)	(74)
Change in cash and cash equivalents, during the year	**2**	(5)
Cash and cash equivalents, beginning of year	**7**	12
Cash and cash equivalents, end of year	**9**	7
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest	**153**	154
Cash payments of income taxes	**67**	8

(See accompanying notes)

UNION GAS LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2012 AND 2011

1. Summary of Operations and Significant Accounting Policies

The terms ("Union Gas" or "the Company") as used in these Consolidated Financial Statements refer collectively to Union Gas Limited and its subsidiary unless the context suggest otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. Union Gas' common stock is held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

Nature of Operations

Union Gas owns and operates natural gas distribution, storage and transmission facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy market participants. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the distribution, storage and transportation of natural gas. In total, the Company has approximately 4,800 kilometres of high-pressure transmission pipeline and approximately 63,200 kilometres of distribution main and service pipelines. The Company's underground natural gas storage facilities have a working capacity of approximately 155 billion cubic feet (Bcf).

Basis of Presentation

The Consolidated Financial Statements of the Company include the accounts of Union Gas and its subsidiary, Huron Tipperary Limited Partnership I, of which the Company owns 75%.

The Consolidated Financial Statements of Union Gas have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP). All amounts are presented in millions of Canadian dollars except where noted.

In 2011, Canadian securities regulators approved the Company's election to report its financial statements in accordance with U.S. GAAP instead of International Financial Reporting Standards, effective January 1, 2012 through December 31, 2014, at which point the Company's intention is to reapply for exemptive relief to continue reporting under U.S. GAAP. For all periods up to and including the year ended December 31, 2011, the Company prepared its Consolidated Annual and Interim Financial Statements in accordance with Part V – Pre-changeover Canadian generally accepted accounting principles (CGAAP). For periods on or after January 1, 2012, the Company has prepared its financial statements to comply with U.S. GAAP. The adoption of U.S. GAAP has been made on a retrospective basis. The Financial Statements for prior periods have been restated in accordance with U.S. GAAP in effect at that time. The Company's date of transition to U.S. GAAP is January 1, 2011. See Note 2 for further details.

Use of Estimates

The preparation of Consolidated Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual amounts could differ from these estimates. Management's significant estimates include unbilled revenue, income tax expense, employee future benefit expense, estimated useful life of property, plant and equipment and asset retirement obligations.

Regulation

The Company is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act*, *(1998)*. This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, with the exception of the items noted below, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within Union Gas and provides the framework required to support new storage investments.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and its ability to achieve forecast revenues and manage costs.

Rates effective January 1, 2007 were approved by the OEB on the basis of the traditional cost of service framework. Effective January 1, 2008, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The Company has set rates for 2013 on a cost of service basis.

The Company follows U.S. GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred, or for certain net revenues beyond a pre-established threshold. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred on the Consolidated Balance Sheets for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the Cost of gas an estimated amount of these differences based upon the methodology used by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

As part of the Company's OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings above an allowable return on equity are shared with ratepayers as a reduction in earnings during the year, if applicable.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Income Taxes

Deferred income taxes are recognized for differences between the financial reporting and tax bases of assets and liabilities at enacted statutory tax rates in effect for the years in which the differences are expected to reverse. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Actual income taxes could vary from these estimates due to the future changes in income tax law or results from the final review of tax returns by federal and provincial tax authorities.

Financial statement effects on tax positions are recognized in the period in which it is more likely than not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest related to the unrecognized tax benefits is recorded as Interest expense.

Inventories

Gas in storage for resale to customers is carried at weighted average cost approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred on the Consolidated Balance Sheets for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment is stated at historical cost less accumulated depreciation and amortization. The Company capitalizes all construction-related direct labour and material costs, as well as indirect construction costs. Indirect costs include general engineering and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred.

Regulated depreciation is computed based on the asset's average service life using the straight-line method. Unregulated depreciation is computed based on management's assumption of useful life using the straight-line method.

When regulated property, plant and equipment is retired, the original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation and amortization. When entire regulated operating units are sold or non-regulated property, plant and equipment is retired, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Asset Retirement Obligations

The Company recognizes asset retirement obligations (AROs) for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within the Company's control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

Stock-Based Compensation

Union Gas employees participate in a stock-based compensation plan sponsored by Spectra Energy. For employee awards, equity classified and liability classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability classified stock-based compensation cost is re-measured at each reporting period until settlement. The compensation cost is recognized as an expense over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible. Awards, including stock options, granted to employees that are already retirement eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

In addition, certain Union Gas employees that previously participated in the Company's 1989 Long Term Incentive Share Plan have the ability to receive a portion of their converted stock option awards as a stock appreciation right (SAR) paid in cash. Union Gas accounts for these by measuring the amount by which the quoted market price of the underlying stock exceeds the SAR base stock price at the balance sheet date.

New Accounting Pronouncements

There were no significant accounting pronouncements adopted during 2012 or 2011 that had a material impact on the Company's Consolidated Financial Statements.

2. First Time Adoption of U.S. GAAP

In 2011, Canadian securities regulators approved the Company's election to report its Consolidated Financial Statements in accordance with U.S. GAAP instead of International Financial Reporting Standards effective January 1, 2012. In March 2012, the OEB approved the use of U.S. GAAP for regulatory purposes.

For all periods up to and including the year ended December 31, 2011, the Consolidated Annual and Interim Financial Statements were prepared in accordance with Part V – Pre-changeover accounting standards of the CICA Handbook.

The Consolidated Financial Statements have been prepared to comply with U.S. GAAP applicable for periods on or after January 1, 2012. The adoption of U.S. GAAP has been made on a retrospective basis. The Consolidated Financial Statements for prior periods have been restated in accordance with U.S. GAAP in effect at that time. The date of transition to U.S. GAAP is January 1, 2011. This note explains the principal adjustments made in restating the Consolidated Balance Sheets as of January 1, 2011 and as of December 31, 2011, the Consolidated Statement of Operations and Comprehensive Income for twelve months ended December 31, 2011 and the Consolidated Statement of Cash Flows for twelve months ended December 31, 2011.

The following reconciliations provide details of the impact of the transition to U.S. GAAP on:

- Consolidated Balance Sheet at January 1, 2011;
- Consolidated Balance Sheet at December 31, 2011;
- Consolidated Statement of Operations and Comprehensive Income for twelve months ended December 31, 2011 and
- Consolidated Statement of Cash Flows for twelve months ended December 31, 2011.

RECONCILIATION OF CONSOLIDATED BALANCE SHEET

As of January 1, 2011 ($millions)	**Previously Reported Under CGAAP**	**Deferred Financing Costs**	**Employee Future Benefits**	**Preferred stock**	**Income Taxes**	**Other**	**Total Adjustments**	**Restated Under U.S. GAAP**
Assets								
Current assets								
Cash and cash equivalents	**12**	–	–	–	–	–	–	**12**
Accounts receivable, net	**516**	–	–	–	–	–	–	**516**
Income taxes receivable	**–**	–	–	–	17	–	17	**17**
Inventories	**174**	–	–	–	–	–	–	**174**
Deferred income taxes	**14**	–	–	–	–	–	–	**14**
Total current assets	**716**	–	–	–	17	–	17	**733**
Property, plant and equipment								
Cost	**6,370**	–	–	–	–	–	–	**6,370**
Accumulated depreciation	**1,994**	–	–	–	–	–	–	**1,994**
Property, plant and equipment, net	**4,376**	–	–	–	–	–	–	**4,376**
Regulatory and other assets	**493**	9	(137)	–	–	(1)	(129)	**364**
Total Assets	**5,585**	9	(137)	–	17	(1)	(112)	**5,473**
Liabilities and Equity								
Current liabilities								
Short-term borrowings	**198**	–	–	–	–	–	–	**198**
Commercial paper	**157**	–	–	–	–	–	–	**157**
Accounts payable and accrued charges	**586**	–	–	–	1	(1)	–	**586**
Income taxes payable	**8**	–	–	–	(8)	–	(8)	**–**
Long-term debt	**250**	–	–	–	–	–	–	**250**
Total current liabilities	**1,199**	–	–	–	(7)	(1)	(8)	**1,191**
Long-term liabilities								
Long-term debt	**1,978**	9	–	–	–	–	9	**1,987**
Mandatorily redeemable preferred stock	**5**	–	–	(5)	–	–	(5)	**–**
Deferred income taxes	**361**	–	–	–	(63)	–	(63)	**298**
Asset retirement obligations	**123**	–	–	–	–	–	–	**123**
Regulatory and other liabilities	**468**	–	115	–	24	–	139	**607**
Total long-term liabilities	**2,935**	9	115	(5)	(39)	–	80	**3,015**
Total Liabilities	**4,134**	9	115	(5)	(46)	(1)	72	**4,206**
Preferred stock	–	–	–	110	–	–	110	**110**
Equity								
Share capital	**732**	–	–	(105)	–	–	(105)	**627**
Retained earnings	**710**	–	–	–	–	–	–	**710**
Accumulated other comprehensive loss	**–**	–	(252)	–	63	–	(189)	**(189)**
Non-controlling interest	**9**	–	–	–	–	–	–	**9**
Total Equity	**1,451**	–	(252)	(105)	63	–	(294)	**1,157**
Total Liabilities and Equity	**5,585**	9	(137)	–	17	(1)	(112)	**5,473**

RECONCILIATION OF CONSOLIDATED BALANCE SHEET

As of December 31, 2011 ($millions)	Previously Reported Under CGAAP	Opening Balance Adjustment	Deferred Financing Costs	Employee Future Benefits	Income Taxes	Cash Pooling	Total Adjustments	Restated Under U.S. GAAP
Assets								
Current assets								
Cash and cash equivalents	**2**	–	–	–	–	5	5	**7**
Accounts receivable, net	**533**	–	–	3	–	–	3	**536**
Inventories	**263**	–	–	–	–	–	–	**263**
Deferred income taxes	**7**	–	–	–	1	–	1	**8**
Total current assets	**805**	–	–	3	1	5	9	**814**
Property, plant and equipment								
Cost	**6,615**	–	–	–	–	–	–	**6,615**
Accumulated depreciation	**2,120**	–	–	–	–	–	–	**2,120**
Property, plant and equipment, net	**4,495**	–	–	–	–	–	–	**4,495**
Regulatory and other assets	**545**	(129)	1	(62)	–	–	(190)	**355**
Total Assets	**5,845**	(129)	1	(59)	1	5	(181)	**5,664**
Liabilities and Equity								
Current liabilities								
Short-term borrowings	**99**	–	–	–	–	–	–	**99**
Commercial paper	**279**	–	–	–	–	–	–	**279**
Accounts payable and accrued charges	**618**	–	–	–	(1)	5	4	**622**
Income taxes payable	**53**	(25)	–	–	(2)	–	(27)	**26**
Total current liabilities	**1,049**	(25)	–	–	(3)	5	(23)	**1,026**
Long-term liabilities								
Long-term debt	**2,277**	9	1	–	–	–	10	**2,287**
Mandatorily redeemable preferred stock	**5**	(5)	–	–	–	–	(5)	**–**
Deferred income taxes	**383**	(63)	–	–	(27)	–	(90)	**293**
Asset retirement obligations	**134**	–	–	–	–	–	–	**134**
Regulatory and other liabilities	**492**	139	–	52	3	–	194	**686**
Total long-term liabilities	**3,291**	80	1	52	(24)	–	109	**3,400**
Total Liabilities	**4,340**	55	1	52	(27)	5	86	**4,426**
Preferred stock	**–**	110	–	–	–	–	110	**110**
Equity								
Share capital	**732**	(105)	–	–	–	–	(105)	**627**
Retained earnings	**764**	–	–	–	–	–	–	**764**
Accumulated other comprehensive loss	**–**	(189)	–	(111)	28	–	(272)	**(272)**
Non-controlling interest	**9**	–	–	–	–	–	–	**9**
Total Equity	**1,505**	(294)	–	(111)	28	–	(377)	**1,128**
Total Liabilities and Equity	**5,845**	(129)	1	(59)	1	5	(181)	**5,664**

RECONCILIATION OF CONSOLIDATED STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME

Twelve Months Ended December 31, 2011 ($millions)	**Previously Reported Under CGAAP**	**Employee Future Benefits**	**Income Taxes**	**Total Adjustments**	**Restated Under U.S. GAAP**
Gas sales and distribution revenue	**1,468**	–	–	–	**1,468**
Cost of gas	**755**	–	–	–	**755**
Gas distribution margin	**713**	–	–	–	**713**
Storage and transportation revenue	**311**	–	–	–	**311**
Other revenue	**34**	–	–	–	**34**
	1,058	–	–	–	**1,058**
Expenses					
Operating and maintenance	**379**	–	–	–	**379**
Depreciation and amortization	**205**	–	–	–	**205**
Property and other taxes	**61**	–	1	1	**62**
	645	–	1	1	**646**
Income before interest and income taxes	**413**	–	(1)	(1)	**412**
Interest expense	**152**	–	1	1	**153**
Income before income taxes	**261**	–	(2)	(2)	**259**
Income taxes	**60**	–	(2)	(2)	**58**
Net income	**201**	–	–	–	**201**
Preferred stock dividends	**2**	–	–	–	**2**
Net income applicable to common stock	**199**	–	–	–	**199**
Other comprehensive loss, net of tax					
Pension and benefits impact	**–**	(83)	–	(83)	**(83)**
Comprehensive income applicable to common stock	**199**	(83)	–	(83)	**116**

RECONCILIATION OF CONSOLIDATED STATEMENT OF CASH FLOWS

Twelve Months Ended December 31, 2011 ($millions)	Previously Reported Under CGAAP	Cash Pooling Adjustment	Restated Under U.S. GAAP
Cash Flows from Operating Activities			
Net income	**201**	–	**201**
Items not affecting cash			
Depreciation and amortization	**205**	–	**205**
Deferred income taxes	**8**	–	**8**
Changes in working capital			
Accounts receivable	**(15)**	–	**(15)**
Inventories	**(85)**	–	**(85)**
Accounts payable, accrued charges and other	**40**	5	**45**
	354	5	**359**
Cash Flows from Investing Activities			
Capital expenditures	**(290)**	–	**(290)**
Cash Flows from Financing Activities			
Net decrease in short-term borrowings	**(99)**	–	**(99)**
Net decrease in commercial paper	**122**	–	**122**
Long-term debt issued	**300**	–	**300**
Long-term debt repayment	**(250)**	–	**(250)**
Dividends paid	**(147)**	–	**(147)**
	(74)	–	**(74)**
Change in cash and cash equivalents, during the period	**(10)**	5	**(5)**
Cash and cash equivalents, beginning of period	**12**	–	**12**
Cash and cash equivalents, end of period	**2**	5	**7**
Supplementary Disclosure of Cash Flow Information:			
Cash payments of interest	**154**		**154**
Cash payments of income taxes	**8**		**8**

Notes to Transitional Adjustments from CGAAP to U.S. GAAP

Deferred Financing Costs

Under CGAAP, deferred financing costs are classified within the balance of Long-term debt. On transition to U.S. GAAP, deferred financing costs of $9 million as of January 1, 2011 and $10 million as of December 31, 2011 have been reclassified from Long-term debt to Regulatory and other assets.

Employee Future Benefits

Under CGAAP, the pension asset or liability is recorded at the net balance of cumulative benefit costs and the cumulative contributions to the plan. Unamortized actuarial gains and losses and prior service costs are not recorded in the pension asset or liability. Under U.S. GAAP, the pension asset or liability is recorded at the present value of the defined benefit obligation less the fair value of plan assets. The pension asset or liability includes unrecognized actuarial gains or losses and prior service costs or credits with an offset to Accumulated other comprehensive loss (AOCL).

On transition, the adjustments made to comply with U.S. GAAP as of January 1, 2011 resulted in a decrease of $137 million to Regulatory and other assets, an increase of $115 million to Regulatory and other liabilities and a loss of $252 million to AOCL. As of December 31, 2011, the adjustments resulted in an increase of $3 million to Accounts receivable, a decrease of $199 million to Regulatory and other assets, an increase of $167 million to Regulatory and other liabilities and a loss of $363 million to AOCL.

Preferred Stock

Under CGAAP, the Company's Class A, Series A and C preferred stock were reported as Long-term debt and the Company's Class A, Series B and Class B, Series 10 preferred stock were reported as Share capital. Under U.S. GAAP, since all of Company's preferred stock are not solely within the Company's control they are reported as temporary equity. On transition to U.S. GAAP, $5 million of preferred stock were reclassified from Mandatorily redeemable preferred stock to Preferred stock and $105 million were reclassified from Share capital to Preferred stock.

Income Taxes

The change in deferred income taxes represents the tax effect of the U.S. GAAP transition adjustments discussed above. U.S. GAAP also requires certain tax reserves to be classified as current and only allows the use of enacted tax rates as opposed to substantively enacted. As of January 1, 2011, this resulted in a decrease of $8 million to Income taxes payable, an increase of $17 million to Income taxes receivable, a decrease of $63 million to Deferred income taxes (liability), an increase of $1 million to Accounts payable and accrued charges, an income of $63 million to AOCL, and an increase of $24 million to Regulatory and other liabilities. As of December 31, 2011, U.S. GAAP adjustments resulted in an increase of $1 million to Deferred income taxes (asset), a decrease of $27 million to Income taxes payable, a decrease of $90 million to Deferred income taxes (liability), an income of $91 million to AOCL, and an increase of $27 million to Regulatory and other liabilities.

Cash Pooling

Under CGAAP, negative book balances may be included as a component of Cash and cash equivalents. Under U.S. GAAP, these balances are reported as liabilities. As of December 31, 2011 negative book balances of $5 million were reclassified from Cash and cash equivalents to Accounts payable and accrued charges.

3. Regulatory Matters

The Company recorded the following assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	**December 31, 2012**	December 31, 2011 (note 2)	Recovery/Settlement Period
Regulatory assets				
Customer deferrals	Accounts receivable, net	**44**	36	Less than 1 year
Gas in storage inventory	Inventories	**15**	54	Less than 1 year
Other deferrals – long-term	Regulatory and other assets	**1**	9	1 – 3 years
Deferred income taxes – long-term	Regulatory and other assets	**298**	235	2 years to exceeds remaining life of asset
Total regulatory assets		**358**	334	
Regulatory liabilities				
Other deferrals – current	Accounts payable and accrued charges	**9**	9	Less than 1 year
Customer deferrals	Accounts payable and accrued charges	**58**	33	Less than 1 year
Gas cost deferrals	Accounts payable and accrued charges	**49**	54	Less than 1 year
Asset removal costs	Regulatory and other liabilities	**444**	427	Exceeds remaining life of asset
Total regulatory liabilities		**560**	523	

Rate Related Information

As 2012 was the final year of the Company's current multi-year incentive regulation framework, the Company filed an application with the OEB in November 2011 to set its distribution rates effective January 1, 2013. As part of the 2013 rates hearing process, the Company conducted settlement negotiations with intervening parties. A settlement agreement was reached on most capital and rate base issues, and on all operating costs. That settlement agreement was accepted by the OEB on July 10, 2012. The unsettled issues, including operating revenue, cost of capital, and rate design, were the subjects of a hearing. On October 25, 2012, the OEB issued its decision on the unsettled issues. The average annual impact on a customer's total bill will range from 0% - 6% depending on their location and customer class. The draft rate order was filed with the OEB in December 2012, and approved in January 2013. The Company implemented the approved OEB rate order in February 2013. During 2013, the Company intends to apply to the OEB for another incentive regulation framework effective for 2014 and beyond.

Non-Commodity Deferral Account Disposition

In April 2011, the Company applied to the OEB for the annual disposition of the 2010 non-commodity deferral account balances. A decision on that application was issued by the OEB in January 2012, and a final rate order was approved in March 2012. In May 2012, pursuant to certain intervenor correspondence, the OEB commenced a proceeding to reconsider the sharing of short-term storage margins between ratepayers and Union Gas. Written submissions were made on May 11, 2012, and a second decision on this matter was issued by the OEB on July 18, 2012. In that revised decision, the OEB directed Union Gas to dispose of an incremental credit balance of $3 million to ratepayers as part of the October 2012 Quarterly Rate Adjustment Mechanism. On August 24, 2012, the Company filed a motion to review and vary the revised decision which was dismissed by the OEB without a hearing.

In April 2012, the Company applied to the OEB for the annual disposition of the 2011 non-commodity deferral account balances. The combined impact on customers, including the impact of incentive regulation earnings sharing for 2011 is a refund payable to customers of approximately $3 million. The OEB decision on the sharing of short-term storage margins, discussed above, increased this refund payable to customers to $6 million.

In August 2012, the OEB determined that it would review the treatment of 2011 revenues derived from the optimization of the Company's upstream transportation contracts as part of the application to dispose of the 2011 non-commodity deferral account balances. The Company has historically recorded the optimization of upstream transportation contracts as revenues based on rates approved by the OEB. However, the OEB decision on the Company's 2013 rates application issued October 25, 2012 found that, among other things, the revenues associated with the optimization of upstream transportation contracts effective in 2013 are to be considered a reduction of natural gas supply costs, 90% of which are to be credited to customers.

On November 19, 2012, the OEB issued its decision on the treatment of 2011 revenues derived from the optimization of the Company's upstream transportation contracts. Similar to its finding in the 2013 rates application, the OEB determined retroactively that certain optimization revenue for 2011 will be treated as a reduction to natural gas supply costs. The result of this decision is to further increase the refund payable to customers for the 2011 non-commodity deferral account balances by $5 million to an approximate total of $11 million. The Company has appealed this decision to the Ontario Divisional Court (the Court) on the basis of impermissible retroactive ratemaking. A hearing and decision by the Court is expected by the end of 2013.

With respect to 2012, the above-mentioned finding on the treatment of certain revenues derived from the optimization of the Company's upstream transportation contracts resulted in a payable to customers of approximately $34 million. This amount has been recorded in the 2012 Consolidated Financial Statements.

Management believes that the effects of the above matters will not have a material adverse effect on the Company's future Consolidated Financial Statements.

4. Gas Imbalances

The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Consolidated Balance Sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

At December 31, 2012 Accounts receivable, net and Accounts payable and accrued charges include $250 million (2011 – $195 million) related to gas imbalances and gas balancing services.

5. Inventories

Gas in storage includes gas for delivery to customers and for use in the Company's operations. Inventories of materials and supplies are for use in Company's operations.

($millions)	**December 31, 2012**	December 31, 2011
Gas in storage	**182**	247
Materials and supplies	**17**	16
	199	263

6. Property, Plant and Equipment, net

($millions)	**Useful Life**	**December 31, 2012**	December 31, 2011
	(years)		
Plant			
Natural gas transmission	30 – 50	**1,653**	1,642
Natural gas distribution	27 – 60	**3,824**	3,680
Storage	5 – 50	**853**	845
Land rights and rights of way	45 – 60	**107**	106
Other buildings and improvements	10 – 38	**49**	43
Equipment	4 – 15	**87**	81
Vehicles	10	**48**	52
Land	—	**42**	42
Construction in progress	—	**52**	39
Software	4	**65**	60
Other	15 – 20	**23**	25
Total Property, plant and equipment		**6,803**	6,615
Total accumulated depreciation		**2,180**	2,062
Total accumulated amortization		**56**	58
Total Property, plant and equipment, net		**4,567**	4,495

The Company had no capital leases at December 31, 2012 or 2011.

Almost 95% of the Company's property, plant and equipment is regulated with estimated useful lives based on rates approved by the OEB. Composite weighted-average depreciation rates were 3.25% for 2012 and 3.25% for 2011.

Amortization expense of intangible assets totalled $15 million in 2012 and $16 million in 2011. Estimated amortization expense for the next five years follows:

($millions)	**2013**	**2014**	**2015**	**2016**	**2017**
Estimated amortization expense	13	11	8	4	2

7. Debt and Credit Facilities

Long-term Debt

($millions)		**December 31, 2012**	December 31, 2011 (note 2)
7.90%	1994 Series debentures, due February 24, 2014	**150**	150
11.50%	1990 Series debentures, due August 28, 2015	**150**	150
4.64%	Series 5, due June 30, 2016	**200**	200
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
4.85%	Series 7, due April 25, 2022	**125**	125
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9, due June 21, 2041	**300**	300
		2,290	2,290
Less: unamortized debt discount		**3**	3
		2,287	2,287

The Company's long-term debt is unsecured. The weighted average cost of long-term debt as at December 31, 2012 was 6.6% (2011 – 6.6%). Principal repayment requirements on long-term debt are as follows:

($millions)	**Total**	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**
Long-term debt	2,290	–	150	150	200	125	1,665

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2012 and 2011, the Company is in compliance with all such covenants.

Total interest paid on long-term debt in 2012 was $150 million (2011 – $151 million).

Available Credit Facility and Restrictive Debt Covenants

			Commercial Paper Outstanding at	
($millions)	**Expiration Date**	**Credit Facility Capacity**	**December 31, 2012**	December 31, 2011
Multi-year syndicated [a]	2016	400	374	279

[a] The credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 68% at December 31, 2012 (2011 – 68%, as adjusted per note 2).

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2012 and 2011 there were no letters of credit issued under the credit facility or revolving borrowings outstanding.

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2012 and 2011, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries.

A majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2012 was 1.12% (2011 – 1.05%).

Total interest paid on short-term debt in 2012 was $4 million (2011 – $3 million).

8. Preferred Stock

		Outstanding			
	Authorized	**December 31, 2012**	December 31, 2011 (note 2)	**December 31, 2012**	December 31, 2011 (note 2)
	(shares)	*(shares)*		*($millions)*	
Class A	202,072				
Series A, 5.5%		**47,672**	47,672	**3**	3
Series B, 6%		**90,000**	90,000	**5**	5
Series C, 5%		**49,500**	49,500	**2**	2
Class B, Series 10, 4.88%	Unlimited	**4,000,000**	4,000,000	**100**	100
				110	110

The Class A, Series A and C Preferred stock are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

The Class A, Series B Preferred stock are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preferred stock are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares every five years commencing January 1, 2014. Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2013.

The Company has an unlimited number of authorized 4.79% Class B, Series 11 Preferred stock. These shares are cumulative and redeemable at $25 per share at the option of the Company, and at the option of the holders, convertible back into Series 10 shares every five years. At December 31, 2012 and December 31, 2011 none of these shares were issued or outstanding.

The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other type of securities other than preferred stock. As these shares are not solely in the control of the Company, they have been classified as temporary equity on the Consolidated Balance Sheets.

9. Asset Retirement Obligations

The Company's asset retirement obligations relate to the legal obligation to disconnect, purge and cap abandoned pipelines, capping abandoned storage wells, and in some buildings, special handling and disposition of asbestos if it is disturbed.

The Company has non-asbestos AROs which include easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to the non-asbestos ARO because the fair value of the ARO cannot be reasonably estimated.

The Company's pipeline system is considered a critical component of its business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term. The Company has determined that sufficient information to estimate the fair value of an ARO is not available because the assets are considered permanent with indeterminate useful lives and that sufficient information is not available to estimate a range of potential settlement dates in order to employ a present value technique to estimate fair value.

Asset retirement obligations are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

($millions)	**December 31, 2012**	December 31, 2011
Balance, beginning of year	**134**	123
Accretion expense	**7**	6
Liabilities incurred	**3**	5
Liabilities settled	**(1)**	–
Balance, end of year	**143**	134

10. Stock-Based Compensation

Under the Long Term Incentive Share Option Plan 1989 (1989 Plan), the Company's parent company, Westcoast has granted certain stock options to its employees, including employees of Union Gas. Stock options are granted at an exercise price that equals the market price as defined in the 1989 Plan of Westcoast's shares on the date of grant. The 1989 Plan also provides for share appreciation rights under which the holder of a stock option may, in lieu of exercising the option, exercise the share appreciation right.

The Spectra Energy 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 40 million shares of common stock may be awarded under the 2007 LTIP. Union Gas employees participate in the 2007 LTIP.

Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have ten year terms and generally vest over a three year term. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. Spectra Energy issues new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model is used to estimate the fair value of options at grant date.

Restricted, performance and phantom stock awards granted under the 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability-classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period which is the same as the vesting period.

At the time of the Spectra Energy spin-off from Duke Energy Corporation (Duke Energy), Duke Energy converted stock options, restricted stock awards, performance awards and phantom stock awards (collectively, Stock-Based Awards) of Duke Energy common stock held by Spectra Energy employees and Duke Energy employees. One replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the spin-off. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the 2007 LTIP.

Spectra Energy allocated pre-tax stock-based compensation expense included in continuing operations to Union Gas for 2012 and 2011 as follows, the components of which are further described below:

($millions)	**2012**	2011
Phantom stock	**1**	1
Performance awards	**1**	2
Total	**2**	3

The Company recognized a nominal tax benefit in Net income associated with stock-based compensation expense in 2012. The Company did not recognize a tax benefit in 2011.

Stock Options

	Options	**Weighted-Average Exercise Price U.S. $**	**Weighted-Average Remaining Life (in years)**	**Aggregate Intrinsic Value (millions U.S. $)**
Outstanding, beginning of year	160,115	24	4.2	1
Transfers out	(36,900)	22		
Exercised	(28,562)	25		
Forfeited	(6,753)	32		
Outstanding, end of year	87,900	25	3.8	–
Options exercisable at year-end	87,900	25	3.8	–

The Company did not award non-qualified stock options to employees during 2012 or 2011. As of December 31, 2012 all stock options are fully vested, and as a result, the Company does not expect to recognize future compensation costs related to stock options.

Stock Awards

	Performance Awards		**Phantom Stock Awards**	
	Units	**Weighted-Average Grant Date Fair Value U.S. $**	**Units**	**Weighted-Average Grant Date Fair Value U.S. $**
Outstanding, beginning of year	184,669	25	170,109	20
Transfers out	(33,700)	31	(49,700)	20
Granted	48,600	28	29,900	31
Vested	(63,134)	15	(45,220)	13
Outstanding, end of year	136,435	28	105,089	26
Awards expected to vest	132,161	28	102,010	26

Performance Awards

Under the 2007 LTIP, the Company can also grant stock-based and cash-based performance awards. The performance awards generally vest over three years at the earliest, if performance metrics are met. The cash-based awards will be settled in cash at vesting. The Company granted 24,300 stock-based awards in 2012 and 31,800 stock-based awards in 2011, with fair values of U.S. $1 million for each of the grants to employees. The Company granted 24,300 cash-based awards in 2012 and 31,800 cash-based awards in 2011, with fair values of less than $1 million in 2012 and U.S. $1 million in 2011. The unvested and outstanding performance awards granted contain market conditions based on the total shareholder return of Spectra Energy common stock relative to a pre-defined peer group. The stock-based and cash-based awards are valued using the Monte Carlo valuation method. The cash-based awards are re-measured at each reporting period until settlement.

Weighted-Average Assumptions for Stock-Based Performance Awards

	2012	2011
Risk free interest rate	**0.4%**	1.2%
Expected life (years)	**3**	3
Expected volatility Spectra Energy	**25.1%**	37.7%
Expected volatility Peer Group	**15.8-41.5%**	21.2-59.6%
Market Index	**20.3%**	30.3%

The risk-free rate of return was determined based on a yield of three year U.S. Treasury bonds on the grant date. The expected volatility was established based on historical volatility over three years using daily stock price observations. A shorter period was used if three years of data was not available. Because the award payout includes dividend equivalents, no dividend yield assumption is required.

The total fair value of the performance shares vested was U.S. $1 million in both 2012 and 2011. As of December 31, 2012, the Company expects to recognize U.S. $1 million of future compensation cost related to stock awards over a weighted-average period of less than two years.

Phantom Stock Awards

Stock-based phantom awards granted under the 2007 LTIP generally vest over three years. The Company granted 29,900 phantom awards in 2012 and 47,200 phantom awards in 2011, with fair values of U.S. $1 million in both 2012 and 2011.

The total fair value of the phantom shares vested was U.S. $1 million in both 2012 and 2011. As of December 31, 2012, the Company expects to recognize U.S. $1 million of future compensation cost related to stock awards over a weighted-average period of less than two years.

11. Fair Value Measurements

Financial instruments recorded at fair value on the Consolidated Balance Sheets are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of the Company’s financial instruments that are actively traded in the secondary market, including Long-term debt, are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency.

Level 3 Valuation Techniques

Level 3 valuation techniques include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts that could have been realized in current markets.

	December 31, 2012		December 31, 2011	
($millions)	**Book Value**	**Approximate Fair Value**	Book Value	Approximate Fair Value
Long-term debt, including current maturities[(a)]	**2,290**	**2,844**	2,290	2,849

[(a)] Excludes unamortized items.

The fair value of the Company's Long-term debt is determined based on market-based prices as described in the Level 2 valuation technique above.

The fair values of Cash and cash equivalents, Accounts receivable, net and Accounts payable and accrued charges, Short-term borrowings and Commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligation. The maximum exposure to credit risk of the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement amount of gas loans at December 31, 2012 is $61 million receivable (2011 - $64 million receivable). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

The Company manages its credit risk on Cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on Accounts receivable, net the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2012 amounted to $40 million (2011 - $48 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

Union Gas continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31, 2012**	December 31, 2011
Current	**249**	263
30 Days over due	**9**	10
60 Days over due	**3**	4
90+ Days over due	**6**	7
Total trade accounts receivable	**267**	284
Allowance for doubtful accounts	**(5)**	(4)
Total trade accounts receivable, net[14]	**262**	280

For the years ended December 31, 2012 and 2011, no one customer accounted for more than 10% of sales or 10% of receivables.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 7).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2012:

($millions)	Total	2013	2014–2015	2016–2017	Thereafter
Short-term borrowings	9	9	–	–	–
Commercial paper	374	374	–	–	–
Accounts payable and accrued charges	685	685	–	–	–
Long-term debt (including principal and interest)	4,247	150	573	552	2,972
Total	5,315	1,218	573	552	2,972

12. Employee Benefit Plans

Retirement Plans

The Company maintains registered and non-registered, contributory and non-contributory defined benefit (DB Plans) and defined contribution (DC Plan) retirement plans covering substantially all employees. The DB Plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC Plan, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings. The Company also provides non-registered DB Plans to all employees who retire under a registered DB Plan and whose pension is limited by the maximum pension limits under the Income Tax Act.

The Company's policy is to fund the retirement plans, where applicable, on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. Total contributions to the DB Plans were $59 million in 2012 and $89 million in 2011. Contributions of $5 million in 2012 and $5 million in 2011 were made to the Company's DC Plan. The Company anticipates that in 2013 it will make total contributions of approximately $59 million to its DB Plans and $6 million to its DC Plan.

[14] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

Actuarial gains and losses are amortized over the average remaining service period of active employees. The average remaining service periods of active employees covered by the registered and non-registered DB Plans are 10 years and 14 years respectively. The Company determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over three years.

Registered and Non-registered Pension Plans

Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

($millions)	**2012**	2011 (note 2)
Change in Projected Benefit Obligation		
Projected benefit obligation, beginning of year	**745**	637
Service cost	**18**	12
Interest cost	**32**	33
Actuarial loss	**21**	92
Participant contributions	**3**	3
Benefits paid	**(32)**	(32)
Projected benefit obligation, end of year	**787**	745
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**591**	529
Actual return on plan assets	**37**	2
Benefits paid	**(32)**	(32)
Employer contributions	**59**	89
Plan participants' contributions	**3**	3
Plan assets, end of year	**658**	591
Net amount recognized[a]	**(129)**	(154)
Accumulated Benefit Obligation	**734**	695

[a] Recognized in Regulatory and other liabilities on the Consolidated Balance Sheets.

The DB Plans had accumulated benefit obligations in excess of plan assets.

Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)

($millions)	**December 31, 2012**	December 31, 2011 (note 2)
Net actuarial loss	**328**	327
Prior service costs	**8**	10
Total amounts recognized in AOCI	**336**	337

Components of Net Periodic Pension Costs

($millions)	2012	2011 (note 2)
Net Periodic Pension Cost		
Service cost benefit earned	**18**	12
Interest cost on projected benefit obligation	**32**	33
Expected return on plan assets	**(43)**	(34)
Amortization of prior service cost	**2**	1
Amortization of loss	**26**	21
Net periodic pension cost	**35**	33
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial loss	**27**	124
Amortization of actuarial loss	**(26)**	(21)
Amortization of prior service cost	**(2)**	(1)
Total recognized in other comprehensive income	**(1)**	102
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	**34**	135

At December 31, 2012, approximately $25 million of actuarial losses will be amortized from AOCI on the Consolidated Balance Sheets into net periodic pension cost in 2013.

At December 31, 2012, approximately $2 million of prior service costs will be amortized from AOCI on the Consolidated Balance Sheets into net periodic pension costs in 2013.

Assumptions Used for Pension Benefits Accounting

	2012	2011
Benefit Obligations		
Discount rate	**4.15%**	4.30%
Salary increase	**3.25%**	3.25%
Net Periodic Benefit Cost		
Discount rate	**4.30%**	5.25%
Salary increase	**3.25%**	3.25%
Expected long-term rate of return on plan assets	**7.10%**	7.00%

The discount rates used to determine the benefit obligations are the rates at which the benefit obligations could be effectively settled. The discount rates are developed from yields on available high-quality bonds and reflect each plan’s expected cash flows.

The long-term rates of return for the plan assets as of December 31, 2012 were developed using weighted-average calculations of expected returns based primarily on future expected returns across classes considering the use of active asset managers applied against the plans’ respective targeted asset mix.

Registered Pension Plan Assets

Asset Category	Target Allocation	**December 31, 2012**	December 31, 2011
U.S. equity securities	14%	**14%**	14%
Canadian equity securities	28%	**28%**	27%
Other equity securities	13%	**13%**	13%
Fixed income securities	45%	**45%**	46%
Total	100%	**100%**	100%

Pension plan assets are maintained in a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. The Company regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The following table summarizes the fair values of pension plan assets recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in note 11:

($millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
December 31, 2012				
Cash and cash equivalents	4	4	–	–
Fixed income securities	297	287	10	–
Equity securities	356	258	98	–
Other	1	–	–	1
Total	658	549	108	1
December 31, 2011				
Cash and cash equivalents	4	4	–	–
Fixed income securities	268	257	11	–
Equity securities	317	227	90	–
Other	2	–	–	2
Total	591	488	101	2

Expected Benefit Payments

($millions)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018–2022**
Expected benefit payments	35	37	38	40	41	177

Other Post-Retirement Benefit Plans

The Company provides health care and life insurance benefits for retired employees on a non-contributory basis predominantly under defined contribution plans. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The other post-retirement benefit plans are not funded.

Other Post-Retirement Benefit Plans – Change in Projected Benefit Obligation and Fair Value of Plan Assets

($millions)	**2012**	2011 (note 2)
Change in Benefit Obligation		
Accumulated post-retirement benefit obligation, beginning of year	**81**	68
Service cost	**3**	2
Interest cost	**3**	4
Actuarial loss (gain)	**(17)**	9
Benefits paid	**(3)**	(2)
Accumulated post-retirement benefit obligation, end of year	**67**	81
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**–**	–
Benefits paid	**(3)**	(2)
Employer contributions	**3**	2
Plan assets, end of year	**–**	–
Net amount recognized[a]	**67**	81

[a] Recognized in Regulatory and other liabilities on the Consolidated Balance Sheets.

Other Post-Retirement Benefit Plans – Amounts Recognized in AOCI

($millions)	**December 31, 2012**	December 31, 2011 (note 2)
Net actuarial loss recognized in AOCI	**8**	26

($millions)	**2012**	2011 (note 2)
Other Post-Retirement Benefit Plans – Components of Net Periodic Benefit Cost		
Service cost benefit earned	**3**	2
Interest cost on accumulated post-retirement benefit obligation	**3**	4
Amortization of loss	**1**	–
Net periodic other post-retirement benefit cost	**7**	6
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial loss (gain)	**(17)**	9
Amortization of actuarial gain	**(1)**	–
Total recognized in other comprehensive income	**(18)**	9
Total recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**(11)**	15

Other Post-Retirement Benefits Plans – Assumptions Used for Benefits Accounting

	2012	2011
Benefit Obligations		
Discount rate for post-retirement plans	**4.20%**	4.33%
Salary increase	**3.25%**	3.25%
Net Periodic Benefit Cost		
Discount rate for post-retirement plans	**4.33%**	5.31%
Salary increase	**3.25%**	3.25%

The discount rates used to determine the post-retirement obligations are the rates at which the benefit obligations could be effectively settled. The discount rates for the plans are developed from yields on available high-quality bonds in each country and reflect each plan's expected cash flows.

Assumed Health Care Cost Trend Rates

	2012	2011
Health care cost trend rate assumed for next year	**7.00%**	7.50%
Rate to which the cost trend rate is assumed to decline	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**2017**	2017

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

($millions)	**1% Point Increase**	1% Point Decrease
Effect on total service and interest costs	**1**	(1)
Effect on post-retirement benefit obligations	**5**	(4)

Other Post-Retirement Benefit Plans – Payments and Receipts

The Company expects to make future benefit payments, which reflect expected future service, as appropriate. The following benefit payments are expected to be paid over each of the next five years and thereafter.

($millions)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018–2022**
Expected benefit payments	3	3	3	3	3	19

Retirement Savings Plan

The Company has employee savings plans available to eligible employees. Employees may participate in a matching contribution where the Company matches a certain percentage of before-tax employee contributions of up to 5% of eligible pay per pay period. The Company expensed pre-tax employer matching contributions of $7 million in 2012 and $7 million in 2011.

13. Income Taxes

Income Tax Expense Components

($millions)	**2012**	2011 (note 2)
Current		
Federal	**30**	36
Provincial	**18**	14
Total current tax expense	**48**	50
Deferred		
Federal	**(7)**	2
Provincial	**(1)**	6
Total deferred tax expense	**(8)**	8
Total Income taxes	**40**	58

Reconciliation of Income Tax Expense at the Combined Federal and Ontario Statutory Tax Rate to Actual Income Tax Expense

($millions)	**2012**	2011 (note 2)
Income before income taxes	**210**	259
Statutory income tax rate	**26.5%**	28.25%
Statutory income tax rate applied to accounting income	**55**	73
Increase/(decrease) resulting from:		
Deferred tax expense resulting from Ontario tax rate change	**4**	–
Deferred regulatory income tax payable/receivable recorded through tax expense	**(23)**	(19)
Other – net	**4**	4
Total income tax expense	**40**	58
Effective rate of income tax	**19.0%**	22.4%

Net Deferred Income Tax Liability Components

($millions)	**December 31, 2012**	December 31, 2011 (note 2)
Deferred income tax liabilities		
Accelerated depreciation rates	**316**	286
Regulatory asset	**79**	59
Other	**(43)**	(52)
Total deferred income tax liabilities	**352**	293
Deferred income tax assets		
Reserves	**11**	6
Regulatory liability	**2**	2
Other	**1**	–
Total deferred income tax assets	**14**	8
Net deferred income tax liabilities	**338**	285

The above deferred tax amounts have been classified in the Consolidated Balance Sheets as follows:

($millions)	**December 31, 2012**	December 31, 2011 (note 2)
Current assets	**14**	8
Long-term liabilities	**(352)**	(293)
	(338)	(285)

Reconciliation of Gross Unrecognized Income Tax Benefits

($millions)	**December 31, 2012**	December 31, 2011 (note 2)
Balance, beginning of year	**22**	22
Increases related to prior year tax positions	**3**	3
Decreases related to prior year tax positions	**–**	(3)
Increases related to current year tax positions	**1**	1
Reductions due to lapse of statute of limitations	**–**	(1)
Balance, end of year	**26**	22

Unrecognized tax benefits totalled $26 million at December 31, 2012. Of this, $17 million would reduce the effective tax rate if recognized on or after January 1, 2013. The Company recorded an increase of $4 million in gross unrecognized tax benefits during 2012. This resulted in a $4 million increase in tax expense.

The Company recognized potential accrued interest related to unrecognized tax benefits as interest expense. $1 million of interest expense was recognized in both 2012 and 2011. Accrued interest totalled $4 million at December 31, 2012 and $3 million at December 31, 2011.

Although uncertain, the Company believes it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $19 million prior to December 31, 2013. The anticipated changes in unrecognized tax benefits relate to the expiration of statutes of limitations, expected audit settlements and expected changes to legislation.

The Company remains subject to examination for income tax returns for years 2006 through 2011.

14. Related Party Transactions

The Company purchases gas, storage and transportation services at prevailing market prices and under normal trade terms from related parties. During 2012, these purchases totalled $41 million (2011 – $56 million). The Company also provides storage and transportation services to related parties which totalled $1 million during 2012 (2011 – $1 million).

The Company provided administrative, management and other services to related parties totalling $14 million during 2012 (2011 – $12 million), which were billed and recovered at cost. Charges from related parties for administrative and other goods and services were $10 million during 2012 (2011 – $9 million).

At December 31, 2012 the Company had receivable balances of $4 million (2011 – $4 million) and payable balances of $10 million (2011 – $7 million) with related parties, all of which are recorded in Accounts receivable, net and Accounts payable and accrued charges, respectively.

In the normal course of operations, the Company provides or obtains funds from Westcoast on an unsecured basis. During 2012, the Company did not provide funds to Westcoast. The balance outstanding at December 31, 2012 was a payable of $9 million (2011 – $99 million payable). During 2012, interest paid on amounts owing totalled less than $1 million (2011 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

In addition, the Company made dividend payments to GLBE of $162 million during 2012 (2011 – $145 million).

15. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company's potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

16. Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated. The Company has no reason to believe that the ultimate outcome of these matters could have a significant impact on its Consolidated Financial Statements.

17. Subsequent Events

Management has evaluated significant events and transactions that occurred from January 1, 2013 through March 8, 2013, the date the financial statements were filed, and no subsequent events requiring disclosure were noted.

DIRECTORS

David G. Unruh

Stephen W. Baker

Bruce E. Pydee

OFFICERS

Stephen W. Baker
Chair and President

J. Patrick Reddy
Chief Financial Officer

M. Richard Birmingham
Vice President, Regulatory Affairs and Lands

Bruce E. Pydee
Vice President and General Counsel

Janice L. Ferguson
Vice President, Human Resources

Menelaos Ydreos
Vice President, Government, Aboriginal and Public Affairs

Mark J. Isherwood
Vice President, Business Development – Storage and Transmission

Paul Rietdyk
Vice President, Engineering, Construction and Storage and Transmission Operations

Michael P. Shannon
Vice President, Distribution Operations

Joe R. Martucci
Vice President, Finance

Guy G. Buckley
Vice President and Treasurer

Timothy J. Kennedy
Vice President, Federal Government Affairs

Paul K. Haralson
Assistant Treasurer

Patricia M. Rice
Corporate Secretary

Leigh A. Hodgins
Assistant Secretary

Joseph Marra
Assistant Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **CIBC Mellon Trust Company**

Union Gas Limited preferred stock are listed on the Toronto Stock Exchange
Class A Preferred, Series A – 5½% (UNG.PR.C)

Class A Preferred, Series B – 6% (UNG.PR.D)

REGISTERED OFFICE

50 Keil Drive North
Chatham, Ontario N7M 5M1

The Consolidated Financial Statements and all information in this report have been prepared by and are the responsibility of management. The Consolidated Financial Statements have been prepared in conformity with generally accepted accounting principles in the United States and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon Union Gas' system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors is responsible for ensuring that management fulfils its responsibility for financial reporting and for final approval of the Consolidated Financial Statements.

The Board of Directors meets regularly with management, the internal auditors and the shareholders' auditors to review the Consolidated Financial Statements, the Independent Auditor's Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Board of Directors, as does the Director of Internal Audit Services.

Deloitte LLP performed an independent audit of the 2013 and 2012 Consolidated Financial Statements in this report. Their independent professional opinion on the fairness of these Consolidated Financial Statements is included in the Independent Auditor's Report.

March 11, 2014

Stephen W. Baker	J. Patrick Reddy
President	Chief Financial Officer

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Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying consolidated financial statements of Union Gas Limited, which comprise the consolidated balance sheets as at December 31, 2013 and December 31, 2012, and the consolidated statements of operations and comprehensive income, consolidated statements of equity, and consolidated statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2013 and December 31, 2012 and the results of its operations and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
March 11, 2014

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the Years Ended December 31 ($millions)	**2013**	2012
Gas sales and distribution revenue	**1,621**	1,365
Cost of gas (note 13)	**849**	638
Gas distribution margin	**772**	727
Storage and transportation revenue (note 13)	**252**	269
Other revenue	**26**	28
	1,050	1,024
Expenses		
Operating and maintenance (note 13)	**398**	380
Depreciation and amortization	**204**	213
Property and other taxes	**66**	65
	668	658
Income before interest and income taxes	**382**	366
Interest expense (notes 6 and 13)	**154**	156
Income before income taxes	**228**	210
Income taxes (note 12)	**21**	40
Net income	**207**	170
Preferred stock dividends	**3**	3
Net income applicable to common stock	**204**	167
Other comprehensive income, net of tax		
Pension and benefits impact (net of tax of $34 and $nil respectively) (note 11)	**91**	19
Comprehensive income applicable to common stock	**295**	186

(*See accompanying notes)*

CONSOLIDATED BALANCE SHEETS

As at December 31 ($millions)	**2013**	2012
Assets		
Current assets		
Cash and cash equivalents	**10**	9
Accounts receivable, net (notes 3 and 13)	**867**	588
Income taxes receivable (note 12)	**5**	–
Inventories (note 4)	**160**	199
Deferred income taxes (note 12)	**3**	14
Total current assets	**1,045**	810
Property, plant and equipment (note 5)		
Cost	**7,187**	6,803
Accumulated depreciation and amortization	**2,340**	2,236
Property, plant and equipment, net	**4,847**	4,567
Regulatory and other assets (notes 2 and 11)	**483**	406
Total Assets	**6,375**	5,783
Liabilities and Equity		
Current liabilities		
Short-term borrowings (note 13)	–	9
Commercial paper (note 6)	**336**	374
Accounts payable and accrued charges (notes 3 and 13)	**874**	685
Income taxes payable (note 12)	–	26
Current maturities of long-term debt (note 6)	**150**	–
Total current liabilities	**1,360**	1,094
Long-term liabilities		
Long-term debt (note 6)	**2,387**	2,287
Deferred income taxes (note 12)	**408**	352
Asset retirement obligations (note 8)	**328**	143
Regulatory and other liabilities (notes 2 and 11)	**484**	645
Total long-term liabilities	**3,607**	3,427
Total Liabilities	**4,967**	4,521
Preferred Stock (note 7)	**110**	110
Equity		
Common stock, unlimited shares authorized, 57,822,650 outstanding	**627**	627
Retained earnings	**824**	769
Accumulated other comprehensive loss	**(162)**	(253)
Non-controlling interest	**9**	9
Total Equity	**1,298**	1,152
Total Liabilities and Equity	**6,375**	5,783

(See accompanying notes)

Approved by the Board

Director

Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31 ($millions)	**2013**	2012
Operating Activities		
Net income	**207**	170
Items not affecting cash		
Depreciation and amortization	**204**	213
Deferred income taxes	**3**	(8)
Changes in working capital		
Accounts receivable	**(73)**	(6)
Inventories	**22**	49
Account payables, accrued charges and other	**(43)**	15
	320	433
Investing Activities		
Capital expenditures	**(370)**	(271)
Financing Activities		
Net decrease in short-term borrowings	**(9)**	(90)
Net (decrease) increase in commercial paper	**(38)**	95
Long-term debt issued	**250**	–
Dividends paid	**(152)**	(165)
	51	(160)
Change in cash and cash equivalents, during the year	**1**	2
Cash and cash equivalents, beginning of year	**9**	7
Cash and cash equivalents, end of year	**10**	9
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest	**153**	153
Cash payments of income taxes	**42**	67

(See accompanying notes)

CONSOLIDATED STATEMENTS OF EQUITY

($millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total
December 31, 2012	627	769	(253)	9	1,152
Net income	–	207	–	–	207
Other comprehensive income	–	–	91	–	91
Dividends					
Preferred stock	–	(3)	–	–	(3)
Common stock	–	(149)	–	–	(149)
December 31, 2013	627	824	(162)	9	1,298
December 31, 2011	627	764	(272)	9	1,128
Net income	–	170	–	–	170
Other comprehensive income	–	–	19	–	19
Dividends					
Preferred stock	–	(3)	–	–	(3)
Common stock	–	(162)	–	–	(162)
December 31, 2012	627	769	(253)	9	1,152

(*See accompanying notes)*

UNION GAS LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2013 AND 2012

1. Summary of Operations and Significant Accounting Policies

The terms ("Union Gas" or "the Company") as used in these Consolidated Financial Statements refer collectively to Union Gas Limited and its subsidiary unless the context suggest otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. Union Gas' common stock is held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

Nature of Operations

Union Gas owns and operates natural gas distribution, storage and transmission facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy market participants. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the distribution, storage and transportation of natural gas.

Basis of Presentation

The Consolidated Financial Statements of the Company include the accounts of the Company and its subsidiary, Huron Tipperary Limited Partnership I, of which the Company owns 75%.

The Consolidated Financial Statements of the Company have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP). All amounts are presented in millions of Canadian dollars except where noted.

In 2011, Canadian securities regulators approved the Company's election to report its financial statements in accordance with U.S. GAAP instead of International Financial Reporting Standards (IFRS), effective January 1, 2012 through December 31, 2014. In November 2013, the Company applied to Canadian securities regulators to extend its exemptive relief to continue reporting under U.S. GAAP until after a final framework for accounting for rate-regulated activities is available under IFRS. In February 2014, Canadian securities regulators approved the extension of the Company's exemptive relief to continue reporting under U.S. GAAP until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

Use of Estimates

The preparation of Consolidated Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual amounts could differ from these estimates. Management's significant estimates include unbilled revenue, income tax expense, employee future benefit expense, estimated useful life of property, plant and equipment and asset retirement obligations.

Regulation

The Company is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act, (1998)*. This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within the Company and provides the framework required to support new storage investments.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and its ability to achieve forecasted revenues and manage costs.

Rates effective January 1, 2013 were approved by the OEB on the basis of the traditional cost of service framework. Effective January 1, 2014, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts.

The Company follows U.S. GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred, or for certain net revenues beyond a pre-established threshold. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered and collection is reasonably assured. Revenues related to these services provided or products delivered but not yet billed are estimated each month.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred on the Consolidated Balance Sheets for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the Cost of gas an estimated amount of these differences based upon the methodology used by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

As part of the Company’s OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings above an allowable return on equity are shared with ratepayers as a reduction in earnings during the year, if applicable. As the Company was in a cost of service framework for 2013, earnings sharing was not applicable.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Income Taxes

Deferred income taxes are recognized for differences between the financial reporting and tax bases of assets and liabilities at enacted statutory tax rates in effect for the years in which the differences are expected to reverse. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Actual income taxes could vary from these estimates due to the future changes in income tax law or results from the final review of tax returns by federal and provincial tax authorities.

Financial statement effects on tax positions are recognized in the period in which it is more likely than not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest related to the unrecognized tax benefits is recorded as Interest expense.

Inventories

Gas in storage for resale to customers is carried at weighted average cost approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred on the Consolidated Balance Sheets for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment is stated at historical cost less accumulated depreciation and amortization. The Company capitalizes all construction-related direct labour and material costs, as well as indirect construction costs. Indirect costs include general engineering and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred.

Regulated depreciation is computed based on the asset’s average service life using the straight-line method. Unregulated depreciation is computed based on management’s assumption of useful life using the straight-line method.

When regulated property, plant and equipment is retired, the original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation and amortization. When entire regulated operating units are sold or non-regulated property, plant and equipment is retired, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Asset Retirement Obligations

The Company recognizes asset retirement obligations (AROs) for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within the Company’s control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

Stock-Based Compensation

Union Gas employees participate in a stock-based compensation plan sponsored by Spectra Energy. For employee awards, equity classified and liability classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests, the date the employee becomes retirement-eligible, or the date the award market condition is met. Awards, including stock options, granted to employees that are already retirement-eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

In addition, certain Union Gas employees that previously participated in the Company's 1989 Long Term Incentive Share Plan have the ability to receive a portion of their converted stock option awards as a stock appreciation right (SAR) paid in cash. Union Gas accounts for these by measuring the amount by which the quoted market price of the underlying stock exceeds the SAR base stock price at the balance sheet date.

Pension and Other Post-Retirement Benefits

The Company fully recognizes the overfunded or underfunded status of pension and other postretirement benefit plans as Regulatory and other assets, Accounts payable and accrued charges, or Regulatory and other liabilities on the Consolidated Balance Sheets. A plan's funded status is the difference between the fair value of plan assets and the plan's benefit obligation. The Company records deferred plan costs and income (unrecognized losses and gains, and unrecognized prior service costs and credits) in Accumulated other comprehensive loss, until they are amortized to be recognized as a component of benefit expense within Operating and maintenance expenses in the Consolidated Statements of Operations and Comprehensive Income. See note 11 for further discussion.

New Accounting Pronouncements

There were no significant accounting pronouncements adopted during 2013 or 2012 that had a material impact on the Company's Consolidated Financial Statements.

2. Regulatory Matters

Regulatory Assets and Liabilities

The Company recorded the following assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	**December 31, 2013**	December 31, 2012	Recovery/Settlement Period
Regulatory assets [(a)]				
Customer deferrals	Accounts receivable, net	**44**	44	Less than 1 year
Gas in storage inventory [(b)]	Inventories	**2**	15	Less than 1 year
Other deferrals – long-term	Regulatory and other assets	**2**	1	2 – 5 years
Deferred income taxes – long-term	Regulatory and other assets	**327**	298	2 years – exceeds remaining life of asset
Total regulatory assets		**375**	358	
Regulatory liabilities [(a)]				
Other deferrals – current	Accounts payable and accrued charges	**7**	9	Less than 1 year
Customer deferrals	Accounts payable and accrued charges	**55**	58	Less than 1 year
Gas cost deferrals	Accounts payable and accrued charges	**8**	49	Less than 1 year
Asset removal costs [(b)]	Regulatory and other liabilities	**376**	444	Exceeds remaining life of asset
Total regulatory liabilities		**446**	560	

[(a)] All regulatory assets and liabilities are excluded from rate base unless otherwise noted.
[(b)] Included in rate base.

The Company has regulatory assets of $327 million as of December 31, 2013 and $298 million as of December 31, 2012 related to deferred income tax liabilities. Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since substantially all of these timing differences are related to property, plant and equipment costs, recovery of these regulatory assets is expected to occur over the life of those assets.

The Company has regulatory liabilities associated with plant removal costs of $376 million as of December 31, 2013 and $444 million as of December 31, 2012. These regulatory liabilities represent collections from customers under approved rates for future asset removal activities that are expected to occur associated with its regulated facilities. During the year, the Company revised the assumption regarding the expected future cost of abandoning distribution service pipelines resulting in a decrease to the regulatory liability of $99 million. Refer to note 8 for further details.

In addition, the Company has regulatory liabilities of $8 million as of December 31, 2013 and $49 million as of December 31, 2012 representing gas cost collections from customers under approved rates that exceed the actual cost of gas for the associated periods. The Company files quarterly with the OEB to ensure that customers' rates reflect future expected prices based on published forward-market prices. The difference between the approved and actual cost of gas is deferred for future repayment to or refund from customers.

Rate Related Information

The Company's distribution rates, effective January 1, 2013, were approved by the OEB following a cost of service application since 2012 was the final year of a multi-year incentive regulation framework that began January 1, 2008.

In October 2013, the OEB approved a new five-year incentive regulation framework for the Company, which the Company will use to determine the rates it will charge customers for natural gas delivery services beginning January 1, 2014. The parameters of the new framework were determined through a settlement process and negotiated agreement with the key stakeholders who regularly participate in the Company's rates applications and who represent the interests of the Company's customers.

The new incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation,
- rate increases or decreases in the small volume customer classes where average use declines or increases,
- certain adjustments to base rates,
- the continued pass-through of gas commodity, upstream transportation and demand side management costs,
- the additional pass-through of costs associated with major capital investments and certain fuel variances,
- an allowance for unexpected cost changes that are outside of management's control,
- equal sharing of tax changes between the Company and its customers, and
- an earnings sharing mechanism that permits the Company to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.

In October 2013, the Company filed an application with the OEB for new rates effective January 1, 2014 pursuant to the above framework. The OEB declared the Company's existing rates as interim, and a decision from the OEB on this application is expected in 2014.

Non-Commodity Deferral Account Disposition

In November 2012 the OEB issued its decision on the treatment of 2011 revenues derived from the optimization of upstream transportation contracts. The OEB determined that these 2011 revenues would be treated as a reduction to gas costs instead of optimization revenues and included in utility earnings. Optimization revenues had been classified as utility earnings for 2008, 2009 and 2010. This decision, including the effect on the treatment of optimization revenues for 2012, resulted in a net charge of $39 million to the Company on the Consolidated Statements of Operations and Comprehensive Income in 2012. In December 2012, the Company appealed the OEB's decision on the disposition of the 2011 non-commodity deferral account balances to the Ontario Divisional Court (the Court). The basis of the appeal was impermissible retroactive ratemaking. A hearing was held in October 2013 and a decision from the Court was released in December 2013. The Company was unsuccessful in that the majority of the Court was of the view that the OEB did not engage in retroactive ratemaking. The dissenting justice was of the view that the OEB did engage in retroactive ratemaking. This decision can be appealed to the Ontario Court of Appeal (Court of Appeal) if that court grants leave to appeal. In January 2014, the Company filed a notice of motion seeking leave to appeal to the Court of Appeal. A decision from the Court of Appeal on the notice of motion is expected in 2014.

In May 2013, the Company filed an application with the OEB for the annual disposition of the 2012 non-commodity deferral account balances. The application included a proposal that revenues derived from the optimization of upstream transportation contracts in 2012 be treated as optimization revenues and included in utility earnings rather than a reduction to gas costs. The net impact for the 2012 non-commodity deferral account balances, including the impact of earnings sharing, would be a receivable from customers of less than $1 million. If the OEB instead finds that the 2012 revenues earned from the optimization of upstream transportation contracts should be treated as a reduction to gas costs, 90% of which are to be credited to customers, the combined impact would be a refund payable to customers of approximately $17 million, comprised of $39 million in Accounts payable and accrued charges and $22 million in Accounts receivable, net, which is reflected on the Consolidated Balance Sheets at December 31, 2013 and 2012. A hearing was held in October 2013 and a decision from the OEB is pending.

3. Gas Imbalances

The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Consolidated Balance Sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

At December 31, 2013 Accounts receivable, net and Accounts payable and accrued charges include $484 million (2012 – $250 million) related to gas imbalances and gas balancing services.

4. Inventories

Gas in storage includes gas for delivery to customers and for use in the Company's operations. Inventories of materials and supplies are for use in the Company's operations.

($millions)	**December 31, 2013**	December 31, 2012
Gas in storage	**142**	182
Materials and supplies	**18**	17
	160	199

5. Property, Plant and Equipment, net

($millions)	**Useful Life**	**December 31, 2013**	December 31, 2012
	(years)		
Plant			
Natural gas transmission	32 – 58	**1,701**	1,653
Natural gas distribution	25 – 60	**4,094**	3,824
Storage	10 – 50	**868**	853
Land rights and rights of way	48 – 61	**109**	107
Other buildings and improvements	2 – 42	**49**	49
Equipment	4 – 15	**89**	87
Vehicles	6	**52**	48
Land	—	**46**	42
Construction in progress	—	**89**	52
Software	4 – 10	**68**	65
Other	15 – 18	**22**	23
Total Property, plant and equipment		**7,187**	6,803
Total accumulated depreciation		**2,277**	2,180
Total accumulated amortization		**63**	56
Total Property, plant and equipment, net		**4,847**	4,567

The Company had no capital leases at December 31, 2013 or 2012.

95% of the Company's property, plant and equipment is regulated with estimated useful lives based on rates approved by the OEB. Composite weighted-average depreciation rates were 2.99% for 2013 and 3.25% for 2012.

Amortization expense of intangible assets totalled $15 million in 2013 and $15 million in 2012. Estimated amortization expense for the next five years is as follows:

($millions)	**2014**	**2015**	**2016**	**2017**	**2018**
Estimated amortization expense	14	11	7	3	2

6. Debt and Credit Facilities

Summary of Debt and Related Terms

($millions)		**December 31, 2013**	December 31, 2012
7.90%	1994 Series debentures, due February 24, 2014	**150**	150
11.50%	1990 Series debentures, due August 28, 2015	**150**	150
4.64%	Series 5, due June 30, 2016	**200**	200
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
4.85%	Series 6, due April 25, 2022	**125**	125
3.79%	Series 10, due July 10, 2023	**250**	–
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9, due June 21, 2041	**300**	300
Long-term debt principal (including current maturities)		**2,540**	2,290
Less: unamortized debt discount		**3**	3
Add: commercial paper		**336**	374
Total debt		**2,873**	2,661
Less: current maturities of long-term debt		**150**	–
Less: commercial paper		**336**	374
Total long-term debt		**2,387**	2,287

The Company's long-term debt is unsecured. Principal repayment requirements on long-term debt are as follows:

($millions)	**Total**	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**
Long-term debt [(a)]	2,537	150	150	200	125	400	1,512

[(a)] Excludes commercial paper of $336 million.

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2013 and 2012, the Company is in compliance with all such covenants.

Total interest expense on long-term debt in 2013 was $155 million (2012 – $150 million).

Available Credit Facility and Restrictive Debt Covenants

			Commercial Paper Outstanding at	
($millions)	**Expiration Date**	**Credit Facility Capacity**	**December 31, 2013**	December 31, 2012
Multi-year syndicated [(a)]	2016	400	336	374

[(a)] The credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 75% and a provision which requires the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 67% at December 31, 2013 (2012 – 68%).

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2013 and 2012 there were no letters of credit issued under the revolving credit facility or revolving borrowings outstanding. A majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2013 was 1.14% (2012 – 1.12%). The weighted average days to maturity on outstanding commercial paper as of December 31, 2013 was 10 days (2012 – 8 days).

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2013 and 2012, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries.

Total interest expense on short-term debt in 2013 was $3 million (2012 – $4 million).

7. Preferred Stock

		Outstanding			
	Authorized	**December 31, 2013**	December 31, 2012	**December 31, 2013**	December 31, 2012
	(shares)	*(shares)*		*($millions)*	
Class A	202,072				
5.5% Series A		**47,672**	47,672	**3**	3
6% Series B		**90,000**	90,000	**5**	5
5% Series C		**49,500**	49,500	**2**	2
4.88% Class B, Series 10	Unlimited	**4,000,000**	4,000,000	**100**	100
				110	110

The Class A, Series A and C Preferred stock are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

The Class A, Series B Preferred stock are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preferred stock are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares once every five years commencing January 1, 2014. The holders of the Class B, Series 10 Preferred stock did not exercise their option on January 1, 2014 and their next optional conversion date is January 1, 2019. Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2018.

The Company has an unlimited number of authorized 4.79% Class B, Series 11 Preferred stock. These shares are cumulative and redeemable at $25 per share at the option of the Company, and at the option of the holders, convertible back into Series 10 shares every five years. At December 31, 2013 and December 31, 2012 none of these shares were issued or outstanding.

The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other type of securities other than preferred stock. As these shares are not solely in the control of the Company, they have been classified as temporary equity on the Consolidated Balance Sheets.

8. Asset Retirement Obligations

The Company's AROs relate to the legal obligation to disconnect, purge and cap abandoned pipelines, capping abandoned storage wells, and in some buildings, special handling and disposition of asbestos if it is disturbed.

The Company has non-asbestos AROs which include easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to the non-asbestos ARO because the fair value of the ARO cannot be reasonably estimated. The Company's pipeline system is considered a critical component of its business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term. The Company has determined that sufficient information to estimate the fair value of an ARO is not available because the assets are considered permanent with indeterminate useful lives and that sufficient information is not available to estimate a range of potential settlement dates in order to employ a present value technique to estimate fair value.

AROs are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

During the year, the Company revised its estimated future cash flow assumptions resulting in an ARO increase of $183 million, with an offsetting increase of $115 million to Property, plant and equipment – cost, and $31 million to Accumulated depreciation and amortization and a decrease of $99 million to Regulatory and other liabilities. The cash flow change assumptions were substantially related to the expected future cost of abandoning distribution service pipelines.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

($millions)	**December 31, 2013**	December 31, 2012
Balance, beginning of year	**143**	134
Accretion expense	**7**	7
Liabilities settled	**(5)**	(1)
Revisions in estimated cash flows	**183**	3
Balance, end of year	**328**	143

9. Stock-Based Compensation

Under the Long Term Incentive Share Option Plan 1989 (1989 Plan), the Company's parent company, Westcoast has granted certain stock options to its employees, including employees of Union Gas. Stock options are granted at an exercise price that equals the market price as defined in the 1989 Plan of Westcoast's shares on the date of grant. The 1989 Plan also provides for share appreciation rights under which the holder of a stock option may, in lieu of exercising the option, exercise the share appreciation right.

The Spectra Energy 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 40 million shares of common stock may be awarded under the 2007 LTIP. Union Gas employees participate in the 2007 LTIP.

Restricted, performance and phantom stock awards granted under the 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability-classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests, the date the employee becomes retirement-eligible, or the date the award market condition is met.

Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have ten year terms and generally vest over a three year term. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. Spectra Energy issues new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model is used to estimate the fair value of options at grant date. All outstanding stock options are fully vested and, as a result, the Company does not expect to recognize future compensation costs related to stock options.

Spectra Energy allocated pre-tax stock-based compensation expense included in continuing operations to Union Gas for 2013 and 2012 as follows, the components of which are further described below:

($millions)	**2013**	2012
Phantom stock	**1**	1
Performance awards	**2**	1
Total	**3**	2

The Company recognized a nominal tax benefit in Net income associated with stock-based compensation expense in both 2013 and in 2012.

Stock Options

	Options	**Weighted-Average Exercise Price U.S. $**	**Weighted-Average Remaining Life (in years)**	**Aggregate Intrinsic Value (millions U.S.$)**
Outstanding, beginning of year	87,900	25	3.8	–
Exercised	(5,650)	12		
Forfeited	(1,250)	12		
Outstanding, end of year	81,000	26	3.2	1
Options exercisable at year-end	81,000	26	3.2	1

The Company did not award non-qualified stock options to employees during 2013 or 2012. As of December 31, 2013 all stock options are fully vested, and as a result, the Company does not expect to recognize future compensation costs related to stock options.

Stock Awards

	Performance Awards		**Phantom Stock Awards**	
	Units	**Weighted-Average Grant Date Fair Value U.S. $**	**Units**	**Weighted-Average Grant Date Fair Value U.S. $**
Outstanding, beginning of year	136,435	28	105,089	26
Transfers out	(1,900)	27	(1,200)	29
Granted	57,200	37	36,400	30
Vested	(40,967)	31	(38,778)	21
Forfeited	(8,760)	31	(5,894)	30
Outstanding, end of year	142,008	39	95,617	29
Awards expected to vest	138,870	39	93,229	29

Performance Awards

Under the 2007 LTIP, the Company can also grant stock-based and cash-based performance awards. The performance awards generally vest over three years at the earliest, if performance metrics are met. The cash-based awards will be settled in cash at vesting. The Company granted 28,600 stock-based awards in 2013 and 24,300 stock-based awards in 2012, with fair values of U.S. $1 million for each of the grants to employees. The Company granted 28,600 cash-based awards in 2013 and 24,300 cash-based awards in 2012, with fair values of U.S. $1 million in 2013 and less than U.S. $1 million in 2012. The unvested and outstanding performance awards granted contain market conditions based on the total shareholder return of Spectra Energy common stock relative to a pre-defined peer group. The stock-based and cash-based awards are valued using the Monte Carlo valuation method. The cash-based awards are re-measured at each reporting period until settlement.

Weighted-Average Assumptions for Stock-Based Performance Awards

	2013	2012
Risk free interest rate	**0.4%**	0.4%
Expected life (years)	**3**	3
Expected volatility Spectra Energy	**21.0%**	25.1%
Expected volatility Peer Group	**13.3 – 32.8%**	15.8 – 41.5%
Market Index	**16.3%**	20.3%

The risk-free rate of return was determined based on a yield of three year U.S. Treasury bonds on the grant date. The expected volatility was established based on historical volatility over three years using daily stock price observations. A shorter period was used if three years of data was not available. Because the award payout includes dividend equivalents, no dividend yield assumption is required.

The total fair value of the performance awards vested was U.S. $1 million in both 2013 and 2012. As of December 31, 2013, the Company expects to recognize U.S. $2 million of future compensation cost related to performance awards over a weighted-average period of less than two years.

Phantom Stock Awards

Stock-based phantom awards granted under the 2007 LTIP generally vest over three years. The Company awarded 36,400 phantom awards in 2013 and 29,900 phantom awards in 2012, with fair values of U.S. $1 million in both 2013 and 2012.

The total fair value of the phantom awards vested was U.S. $1 million in both 2013 and 2012. As of December 31, 2013, the Company expects to recognize U.S. $1 million of future compensation cost related to phantom awards over a weighted-average period of less than two years.

10. Fair Value Measurements

Financial instruments recorded at fair value on the Consolidated Balance Sheets are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of the Company's financial instruments that are actively traded in the secondary market are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency. The fair value of the Company's pension plan assets designated as Level 2 financial instruments is determined through the market approach valuation technique using observable inputs including matrix pricing and market corroborated pricing.

Level 3 Valuation Techniques

Level 3 valuation techniques include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation. The fair value of the Company's pension plan assets designated as Level 3 financial instruments is determined through the market approach valuation technique using unobservable inputs including investment manager pricing for private placements and private equities.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts that could have been realized in current markets.

	December 31, 2013		December 31, 2012	
($millions)	**Book Value**	**Fair Value**	Book Value	Fair Value
Long-term debt, including current maturities[(a)]	**2,540**	**2,877**	2,290	2,844

[(a)] Excludes unamortized items.

The fair value of the Company's Long-term debt is determined based on market-based prices as described in the Level 2 valuation technique described above.

The fair values of Cash and cash equivalents, Accounts receivable, net, Accounts payable and accrued charges, Short-term borrowings and Commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligation. The maximum exposure to credit risk of the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement amount of gas loans at December 31, 2013 is $132 million receivable (2012 – $61 million receivable). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

The Company manages its credit risk on Cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on Accounts receivable, net the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2013 amounted to $35 million (2012 – $40 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

The Company continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31, 2013**	December 31, 2012
Current	**300**	249
30 Days over due	**11**	9
60 Days over due	**4**	3
90+ Days over due	**7**	6
Total trade accounts receivable	**322**	267
Allowance for doubtful accounts	**(6)**	(5)
Total trade accounts receivable, net[12]	**316**	262

For the years ended December 31, 2013 and 2012, no one customer accounted for more than 10% of sales or 10% of receivables.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 6).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2013:

($millions)	**Total**	**2014**	**2015 – 2016**	**2017 – 2018**	**Thereafter**
Commercial paper	336	336	–	–	–
Accounts payable and accrued charges	874	874	–	–	–
Long-term debt (including principal and interest)	4,437	300	618	741	2,778
Total	5,647	1,510	618	741	2,778

11. Employee Benefit Plans

Retirement Plans

The Company maintains registered and non-registered, contributory and non-contributory defined benefit (DB Plans) and defined contribution (DC Plan) retirement plans covering substantially all employees. The DB Plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC Plan, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings. The Company also provides non-registered DB Plans to all employees who retire under a registered DB Plan and whose pension is limited by the maximum pension limits under the Income Tax Act.

The Company's policy is to fund the retirement plans, where applicable, on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. Total contributions to the DB Plans were $54 million in 2013 and $59 million in 2012. Contributions of $6 million in 2013 and $5 million in 2012 were made to the Company's DC Plan. The Company anticipates that in 2014 it will make total contributions of approximately $20 million to its DB Plans and $6 million to its DC Plan.

Actuarial gains and losses are amortized over the average remaining service period of active employees. The average remaining service periods of active employees covered by the registered and non-registered DB Plans is

[12] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

10 years. The Company determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over three years.

Registered and Non-registered Pension Plans

Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

($millions)	**2013**	2012
Change in Projected Benefit Obligation		
Projected benefit obligation, beginning of year	**787**	745
Service cost	**20**	18
Interest cost	**32**	32
Actuarial (gain) loss	**(60)**	21
Participant contributions	**3**	3
Benefits paid	**(34)**	(32)
Projected benefit obligation, end of year	**748**	787
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**658**	591
Actual return on plan assets	**80**	37
Benefits paid	**(34)**	(32)
Employer contributions	**54**	59
Plan participants' contributions	**3**	3
Plan assets, end of year	**761**	658
Net amount recognized[a]	**13**	(129)
Accumulated Benefit Obligation	**707**	734

[a] At December 31, 2013 the Consolidated Balance Sheets includes $47 million of non-current pension assets recognized in Regulatory and other assets, $33 million of non-current pension liabilities in Regulatory and other liabilities, and $1 million of current pension liabilities in Accounts payable and accrued charges.

The table above includes non-registered pension plans that are not funded and had projected benefit obligations of $34 million at December 31, 2013 and $36 million at December 31, 2012. At December 31, 2013 there were no registered DB plans with accumulated benefit obligations in excess of plan assets. Non-registered DB plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations of $34 million and accumulated benefit obligations of $32 million.

Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)

($millions)	**December 31, 2013**	December 31, 2012
Net actuarial loss	**210**	328
Prior service costs	**6**	8
Total amounts recognized in AOCI, pre-tax	**216**	336

Components of Net Periodic Pension Costs

($millions)	**2013**	2012
Net Periodic Pension Cost		
Service cost benefit earned	**20**	18
Interest cost on projected benefit obligation	**32**	32
Expected return on plan assets	**(47)**	(43)
Amortization of prior service cost	**2**	2
Amortization of loss	**25**	26
Net periodic pension cost	**32**	35
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial (gain) loss	**(93)**	27
Amortization of actuarial loss	**(25)**	(26)
Amortization of prior service cost	**(2)**	(2)
Total recognized in other comprehensive income	**(120)**	(1)
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	**(88)**	34

At December 31, 2013, approximately $18 million of actuarial losses will be amortized from AOCI on the Consolidated Balance Sheets into net periodic pension cost in 2014.

At December 31, 2013, approximately $2 million of prior service costs will be amortized from AOCI on the Consolidated Balance Sheets into net periodic pension costs in 2014.

Assumptions Used for Pension Benefits Accounting

	2013	2012
Benefit Obligations		
Discount rate	**4.81%**	4.15%
Salary increase	**3.25%**	3.25%
Net Periodic Benefit Cost		
Discount rate	**4.15%**	4.30%
Salary increase	**3.25%**	3.25%
Expected long-term rate of return on plan assets	**7.10%**	7.10%

The discount rates used to determine the benefit obligations are the rates at which the benefit obligations could be effectively settled. The discount rates are developed from yields on available high-quality bonds and reflect each plan’s expected cash flows.

The long-term rates of return for the plan assets as of December 31, 2013 were developed using weighted-average calculations of expected returns based primarily on future expected returns across classes considering the use of active asset managers applied against the plans’ respective targeted asset mix.

Registered Pension Plan Assets

Asset Category	Target Allocation	**December 31, 2013**	December 31, 2012
U.S. equity securities	14%	**18%**	14%
Canadian equity securities	28%	**26%**	28%
Other equity securities	13%	**13%**	13%
Fixed income securities	45%	**43%**	45%
Total	100%	**100%**	100%

Pension plan assets are maintained in a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. The Company regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The following table summarizes the fair values of pension plan assets recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in note 10:

($millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
December 31, 2013				
Cash and cash equivalents	4	4	–	–
Fixed income securities	324	324	–	–
Equity securities	433	314	119	–
Other	–	–	–	–
Total	761	642	119	–
December 31, 2012				
Cash and cash equivalents	4	4	–	–
Fixed income securities	297	287	10	–
Equity securities	356	258	98	–
Other	1	–	–	1
Total	658	549	108	1

Expected Benefit Payments

($millions)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019 – 2023**
Expected benefit payments	36	38	40	42	43	228

Other Post-Retirement Benefit Plans

The Company provides health care and life insurance benefits for retired employees on a non-contributory basis predominantly under defined contribution plans. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The other post-retirement benefit plans are not funded.

Other Post-Retirement Benefit Plans – Change in Projected Benefit Obligation and Fair Value of Plan Assets

($millions)	**2013**	2012
Change in Benefit Obligation		
Accumulated post-retirement benefit obligation, beginning of year	**67**	81
Service cost	**2**	3
Interest cost	**3**	3
Actuarial gain	**(5)**	(17)
Benefits paid	**(3)**	(3)
Accumulated post-retirement benefit obligation, end of year	**64**	67
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	–	–
Benefits paid	**(3)**	(3)
Employer contributions	**3**	3
Plan assets, end of year	–	–
Net amount recognized[a]	**64**	67

[a] $61 million is recognized in Regulatory and other liabilities and $3 million is recognized in Accounts payable and accrued charges on the Consolidated Balance Sheets.

Other Post-Retirement Benefit Plans – Amounts Recognized in AOCI

($millions)	**December 31, 2013**	December 31, 2012
Net actuarial loss recognized in AOCI	**3**	8

($millions)	**2013**	2012
Other Post-Retirement Benefit Plans – Components of Net Periodic Benefit Cost		
Service cost benefit earned	**2**	3
Interest cost on accumulated post-retirement benefit obligation	**3**	3
Amortization of loss	–	1
Net periodic other post-retirement benefit cost	**5**	7
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial gain	**(5)**	(17)
Amortization of actuarial loss	–	(1)
Total recognized in other comprehensive income	**(5)**	(18)
Total recognized in Net Periodic Benefit Cost and Other Comprehensive Income	–	(11)

Other Post-Retirement Benefits Plans – Assumptions Used for Benefits Accounting

	2013	2012
Benefit Obligations		
Discount rate for post-retirement plans	**4.83%**	4.20%
Salary increase	**3.25%**	3.25%
Net Periodic Benefit Cost		
Discount rate for post-retirement plans	**4.20%**	4.33%
Salary increase	**3.25%**	3.25%

The discount rates used to determine the post-retirement obligations are the rates at which the benefit obligations could be effectively settled. The discount rates for the plans are developed from yields on available high-quality bonds in each country and reflect each plan's expected cash flows.

Assumed Health Care Cost Trend Rates

	2013	2012
Health care cost trend rate assumed for next year	**6.50%**	7.00%
Rate to which the cost trend rate is assumed to decline	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**2017**	2017

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

($millions)	**1% Point Increase**	1% Point Decrease
Effect on total service and interest costs	**1**	–
Effect on post-retirement benefit obligations	**5**	(4)

Other Post-Retirement Benefit Plans – Payments and Receipts

The Company expects to make future benefit payments, which reflect expected future service, as appropriate. The following benefit payments are expected to be paid over each of the next five years and thereafter.

($millions)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019 – 2023**
Expected benefit payments	3	3	3	3	4	19

Savings Plan

The Company has employee savings plans available to eligible employees. Employees may participate in a matching contribution where the Company matches a certain percentage of before-tax employee contributions of up to 5% of eligible pay per pay period. The Company expensed pre-tax employer matching contributions of $8 million in 2013 and $7 million in 2012.

12. Income Taxes

Income Tax Expense Components

($millions)	**2013**	2012
Current		
Federal	**12**	30
Provincial	**6**	18
Total current tax expense	**18**	48
Deferred		
Federal	**2**	(7)
Provincial	**1**	(1)
Total deferred tax expense	**3**	(8)
Total Income taxes	**21**	40

Reconciliation of Income Tax Expense at the Combined Federal and Ontario Statutory Tax Rate to Actual Income Tax Expense

($millions)	**2013**	2012
Income before income taxes	**228**	210
Statutory income tax rate	**26.5%**	26.5%
Statutory income tax rate applied to accounting income	**60**	55
Increase/(decrease) resulting from:		
Deferred tax expense resulting from Ontario tax rate change	–	4
Enacted Canadian federal income tax legislation[a]	**(16)**	–
Deferred income tax adjustments related to rate regulated operations	**(23)**	(23)
Other – net	–	4
Total income tax expense	**21**	40
Effective rate of income tax	**9.2%**	19.0%

[a] Due to the recognition of tax benefits associated with favourable Canadian federal income tax legislation enacted on June 26, 2013 (Enacted Legislation). The Enacted Legislation contained changes that resulted in increased tax deductions and has a beneficial impact for the tax years 2008 and forward.

Net Deferred Income Tax Liability Components

($millions)	**December 31, 2013**	December 31, 2012
Deferred income tax liabilities		
Accelerated depreciation rates	**328**	316
Regulatory asset	**86**	79
Other	**(6)**	(43)
Total deferred income tax liabilities	**408**	352
Deferred income tax assets		
Reserves	–	11
Regulatory liability	**2**	2
Other	**1**	1
Total deferred income tax assets	**3**	14
Net deferred income tax liabilities	**405**	338

The above deferred tax amounts have been classified in the Consolidated Balance Sheets as follows:

($millions)	**December 31, 2013**	December 31, 2012
Current assets	**3**	14
Long-term liabilities	**(408)**	(352)
	(405)	(338)

Reconciliation of Gross Unrecognized Income Tax Benefits

($millions)	**December 31, 2013**	December 31, 2012
Balance, beginning of year	**26**	22
Increases related to prior year tax positions	**2**	3
Decreases related to prior year tax positions	**(13)**	–
Increases related to current year tax positions	**1**	1
Audit settlements	**(1)**	–
Reductions due to lapse of statute of limitations	**(4)**	–
Balance, end of year	**11**	26

Unrecognized tax benefits totalled $11 million at December 31, 2013. Of this, $2 million would reduce the effective tax rate if recognized on or after January 1, 2014. The Company recorded a decrease of $15 million in gross unrecognized tax benefits during 2013. This resulted in a $15 million decrease in tax expense.

The Company recognized potential accrued interest related to unrecognized tax benefits as interest expense. A $2 million credit was recorded to interest expense in 2013 compared to a $1 million expense in 2012. Accrued interest totalled $2 million at December 31, 2013 and $4 million at December 31, 2012.

Although uncertain, the Company believes it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $5 million prior to December 31, 2014. The anticipated changes in unrecognized tax benefits relate to the expiration of statutes of limitations and expected audit settlements.

The Company remains subject to examination for income tax returns for years 2009 through 2012.

13. Related Party Transactions

The Company purchases gas, storage and transportation services at prevailing market prices and under normal trade terms from related parties. During 2013, these purchases totalled $83 million (2012 – $41 million). The Company also provides storage and transportation services to related parties which totalled $1 million during 2013 (2012 – $1 million).

The Company provided administrative, management and other services to related parties totalling $13 million during 2013 (2012 – $14 million), which were billed and recovered at cost. Charges from related parties for administrative and other goods and services were $11 million during 2013 (2012 – $10 million).

At December 31, 2013 the Company had receivable balances of $5 million (2012 – $4 million) and payable balances of $29 million (2012 – $10 million) with related parties, all of which are recorded in Accounts receivable, net and Accounts payable and accrued charges, respectively.

In the normal course of operations, the Company provides or obtains funds from Westcoast on an unsecured basis. There was no balance outstanding on these loans at December 31, 2013 (2012 – $9 million payable). During 2013, interest paid on these loans totalled less than $1 million (2012 – less than $1 million) and interest received on these loans totalled less than $1 million (2012 – $nil). Interest on these loans is calculated based on the monthly average of 30-day banker’s acceptance rates.

In May 2013, the Company signed a promissory note to borrow up to $150 million from GLBE on an unsecured basis. Funds from this promissory note are used for general corporate purposes. There was no balance outstanding at December 31, 2013. During 2013, interest paid on amounts owing totalled less than $1 million. Interest on amounts owing is calculated based on the monthly average of 30-day banker’s acceptance rates.

In addition, the Company made dividend payments to GLBE of $149 million during 2013 (2012 – $162 million).

14. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company’s potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

15. Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated. The Company has no reason to believe that the ultimate outcome of these matters could have a significant impact on its Consolidated Financial Statements.

16. Subsequent Events

Management has evaluated significant events and transactions that occurred from January 1, 2014 through March 11, 2014, the date the financial statements were filed, and no subsequent events requiring disclosure were noted.

DIRECTORS

David G. Unruh

Stephen W. Baker

Bruce E. Pydee

OFFICERS

Stephen W. Baker
Chair and President

J. Patrick Reddy
Chief Financial Officer

M. Richard Birmingham
Vice President, Regulatory, Lands and Public Affairs

Bruce E. Pydee
Vice President and General Counsel

Janice L. Ferguson
Vice President, Human Resources

Mark J. Isherwood
Vice President, Business Development – Storage and Transmission

Paul Rietdyk
Vice President, Engineering, Construction and Storage and Transmission Operations

Michael P. Shannon
Vice President, Distribution Operations

Joe R. Martucci
Vice President, Finance

Laura J. Sayavedra
Vice President and Treasurer

Timothy J. Kennedy
Vice President, Government and Aboriginal Affairs

David G. Simpson
Vice President, In-Franchise Sales, Marketing and Customer Care

Paul K. Haralson
Assistant Treasurer

Patricia M. Rice
Corporate Secretary

Leigh A. Hodgins
Assistant Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **CST Trust Company**

Union Gas Limited preferred stock are listed on the Toronto Stock Exchange
Class A Preferred, Series A – 5½% (UNG.PR.C)

Class A Preferred, Series B – 6% (UNG.PR.D)

REGISTERED OFFICE

50 Keil Drive North
Chatham, Ontario N7M 5M1

The Consolidated Financial Statements and all information in this report have been prepared by and are the responsibility of management. The Consolidated Financial Statements have been prepared in conformity with generally accepted accounting principles in the United States and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon Union Gas' system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors is responsible for ensuring that management fulfils its responsibility for financial reporting and for final approval of the Consolidated Financial Statements.

The Board of Directors meets regularly with management, the internal auditors and the shareholders' auditors to review the Consolidated Financial Statements, the Independent Auditor's Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Board of Directors, as does the Director of Internal Audit Services.

Deloitte LLP performed an independent audit of the 2014 and 2013 Consolidated Financial Statements in this report. Their independent professional opinion on the fairness of these Consolidated Financial Statements is included in the Independent Auditor's Report.

March 6, 2015

J. Patrick Reddy

Stephen W. Baker	J. Patrick Reddy
President	Chief Financial Officer

Deloitte.

Deloitte LLP
150 Ouellette Place
Suite 200
Windsor ON N8X 1L9
Canada

Tel: 519-967-0388
Fax: 519-967-0324
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Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying consolidated financial statements of Union Gas Limited, which comprise the consolidated balance sheets as at December 31, 2014 and December 31, 2013, and the consolidated statements of operations and comprehensive income, consolidated statements of equity, and consolidated statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2014 and December 31, 2013 and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
March 3, 2015

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the Years Ended December 31 ($millions)	**2014**	2013
Gas sales and distribution revenue	**1,755**	1,621
Cost of gas (note 13)	**977**	849
Gas distribution margin	**778**	772
Storage and transportation revenue (note 13)	**266**	252
Other revenue, net	**21**	26
	1,065	1,050
Expenses		
Operating and maintenance (note 13)	**397**	398
Depreciation and amortization	**212**	204
Property taxes and other	**69**	66
	678	668
Income before interest and income taxes	**387**	382
Interest expense (notes 6 and 13)	**156**	154
Income before income taxes	**231**	228
Income tax expense (note 12)	**36**	21
Net income	**195**	207
Preferred stock dividends	**3**	3
Net income applicable to common stock	**192**	204
Other comprehensive income, net of tax		
Pension and benefits impact (net of tax of ($12) and $33 respectively) (note 11)	**(33)**	91
Comprehensive income applicable to common stock	**159**	295

(See accompanying notes)

CONSOLIDATED BALANCE SHEETS

As at December 31 ($millions)	**2014**	2013
Assets		
Current assets		
Cash and cash equivalents	**20**	10
Accounts receivable, net (notes 3 and 13)	**1,135**	867
Income taxes receivable (note 12)	**17**	5
Inventories (note 4)	**239**	160
Deferred income taxes (note 12)	**—**	3
Total current assets	**1,411**	1,045
Property, plant and equipment (note 5)		
Cost	**7,627**	7,187
Accumulated depreciation and amortization	**2,473**	2,340
Property, plant and equipment, net	**5,154**	4,847
Regulatory and other assets (notes 2 and 11)	**480**	483
Total Assets	**7,045**	6,375
Liabilities and Equity		
Current liabilities		
Short-term borrowings (note 13)	**48**	—
Commercial paper (note 6)	**270**	336
Accounts payable and accrued charges (notes 3 and 13)	**1,117**	874
Current maturities of long-term debt (note 6)	**150**	150
Deferred income taxes (note 12)	**25**	—
Total current liabilities	**1,610**	1,360
Long-term liabilities		
Long-term debt (note 6)	**2,687**	2,387
Deferred income taxes (note 12)	**417**	408
Asset retirement obligations (note 8)	**368**	328
Regulatory and other liabilities (notes 2 and 11)	**497**	484
Total long-term liabilities	**3,969**	3,607
Total Liabilities	**5,579**	4,967
Preferred Stock (note 7)	**110**	110
Equity		
Common stock, unlimited shares authorized, 57,822,650 outstanding	**627**	627
Retained earnings	**916**	824
Accumulated other comprehensive loss	**(195)**	(162)
Non-controlling interest	**8**	9
Total Equity	**1,356**	1,298
Total Liabilities and Equity	**7,045**	6,375

(See accompanying notes)

Approved by the Board

Director

Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31 ($millions)	**2014**	2013
Operating Activities		
Net income	**195**	207
Items not affecting cash		
Depreciation and amortization	**212**	204
Loss on disposal of assets	**1**	—
Deferred income taxes	**13**	3
Changes in working capital		
Accounts receivable	**(89)**	(73)
Inventories	**(112)**	22
Accounts payable, accrued charges and other	**85**	(43)
	305	320
Investing Activities		
Capital expenditures	**(474)**	(370)
Financing Activities		
Net increase (decrease) in short-term borrowings	**48**	(9)
Net decrease in commercial paper	**(66)**	(38)
Long-term debt issued	**450**	250
Long-term debt repayments	**(150)**	—
Dividends paid	**(103)**	(152)
	179	51
Change in cash and cash equivalents, during the year	**10**	1
Cash and cash equivalents, beginning of year	**10**	9
Cash and cash equivalents, end of year	**20**	10
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest	**164**	153
Cash payments of income taxes	**26**	42

(See accompanying notes)

CONSOLIDATED STATEMENTS OF EQUITY

($millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total
December 31, 2013	627	824	(162)	9	1,298
Net income	—	195	—	—	195
Other comprehensive income	—	—	(33)	—	(33)
Dividends					
Preferred stock	—	(3)	—	—	(3)
Common stock	—	(100)	—	—	(100)
Other	—	—	—	(1)	(1)
December 31, 2014	627	916	(195)	8	1,356
December 31, 2012	627	769	(253)	9	1,152
Net income	—	207	—	—	207
Other comprehensive income	—	—	91	—	91
Dividends					
Preferred stock	—	(3)	—	—	(3)
Common stock	—	(149)	—	—	(149)
December 31, 2013	627	824	(162)	9	1,298

(See accompanying notes)

UNION GAS LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2014 AND 2013

1. Summary of Operations and Significant Accounting Policies

The terms ("Union Gas" or "the Company") as used in these Consolidated Financial Statements refer collectively to Union Gas Limited and its subsidiary unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. Union Gas' common stock is held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

Nature of Operations

Union Gas owns and operates natural gas distribution, storage and transmission facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy market participants. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the distribution, storage and transportation of natural gas.

Basis of Presentation

The Consolidated Financial Statements of the Company include the accounts of the Company and its subsidiary, Huron Tipperary Limited Partnership I (HTLP), of which the Company owns 75%. Subsequent to the year-end, the Company acquired the remaining 25% of HTLP. See note 16 for further information.

The Consolidated Financial Statements of the Company have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP). All amounts are presented in millions of Canadian dollars except where noted.

In February 2014, Canadian securities regulators approved the extension of the Company's exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

Use of Estimates

The preparation of the Consolidated Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual amounts could differ from these estimates.

Regulation

The Company is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act, (1998)*. This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within the Company and provides the framework required to support new storage investments.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and its ability to achieve forecasted revenues and manage costs.

Rates effective January 1, 2013 were approved by the OEB on the basis of the traditional cost of service framework. Effective January 1, 2014, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts.

The Company follows U.S. GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered and collection is reasonably assured. Revenues related to these services provided or products delivered but not yet billed are estimated each month.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred on the Consolidated Balance Sheets for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the Cost of gas an estimated amount of these differences based upon the methodology used by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

As part of the Company's OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings above an allowable return on equity are shared with ratepayers as a reduction in earnings during the year, if applicable.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Income Taxes

Deferred income taxes are recognized for differences between the financial reporting and tax bases of assets and liabilities at enacted statutory tax rates in effect for the years in which the differences are expected to reverse. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Actual income taxes could vary from these estimates due to the future changes in income tax law or results from the final review of tax returns by federal and provincial tax authorities.

Financial statement effects on tax positions are recognized in the period in which it is more likely than not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest related to the unrecognized tax benefits is recorded as Interest expense.

Inventories

Gas in storage for resale to customers is carried at weighted average cost approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred on the Consolidated Balance Sheets for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment is stated at historical cost less accumulated depreciation and amortization. The Company capitalizes all construction-related direct labour and material costs, as well as indirect construction costs. Indirect costs include general engineering and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred.

Regulated depreciation is computed based on the asset's average service life using the straight-line method. Unregulated depreciation is computed based on management's assumption of useful life using the straight-line method.

When regulated property, plant and equipment is retired, the original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation and amortization. When entire regulated operating units are sold or non-regulated property, plant and equipment is retired, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Asset Retirement Obligations

The Company recognizes asset retirement obligations (AROs) for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within the Company's control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

Stock-Based Compensation

Union Gas employees participate in a stock-based compensation plan sponsored by Spectra Energy. For employee awards, equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests, the date the employee becomes retirement-eligible, or the date the award market condition is met. Awards, including stock options, granted to employees that are already retirement-eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

Pension and Other Post-Retirement Benefits

The Company fully recognizes the overfunded or underfunded status of pension and other post-retirement benefit plans as Regulatory and other assets, Accounts payable and accrued charges, or Regulatory and other liabilities on the Consolidated Balance Sheets. A plan's funded status is the difference between the fair value of plan assets and the plan's benefit obligation. The Company records deferred plan costs and income (unrecognized losses and gains, and unrecognized prior service costs and credits) in Accumulated other comprehensive loss, until they are amortized to be recognized as a component of benefit expense within Operating and maintenance expenses in the Consolidated Statements of Operations and Comprehensive Income. See note 11 for further discussion.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued an Accounting Standards Update (ASU) on Revenue from Contracts with Customers, Topic 606, which supersedes the revenue recognition requirements of Topic 605, Revenue Recognition, and clarifies the principles of recognizing revenue. For the Company, this ASU is effective for the reporting period beginning January 1, 2017 and is to be applied retrospectively. The Company is currently evaluating the potential impact to the Consolidated Financial Statements. There were no significant accounting pronouncements adopted during 2014 that had a material impact on the Company's Consolidated Financial Statements.

2. Regulatory Matters

Regulatory Assets and Liabilities

The Company recorded the following assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	**December 31, 2014**	December 31, 2013	Recovery/Settlement Period
Regulatory assets[a]				
Customer deferrals	Accounts receivable, net	**42**	44	Less than 1 year
Gas cost deferrals	Accounts receivable, net	**67**	—	Less than 1 year
Gas in storage inventory	Inventories	**8**	2	Less than 1 year
Other deferrals – long-term	Regulatory and other assets	**1**	2	2 – 4 years
Deferred income taxes – long-term[b]	Regulatory and other assets	**362**	327	2 years – exceeds remaining life of asset
Total regulatory assets		**480**	375	
Regulatory liabilities[a]				
Other deferrals – current[b]	Accounts payable and accrued charges	**7**	7	Less than 1 year
Customer deferrals	Accounts payable and accrued charges	**28**	55	Less than 1 year
Gas cost deferrals	Accounts payable and accrued charges	**—**	8	Less than 1 year
Asset removal costs[b]	Regulatory and other liabilities	**375**	376	Exceeds remaining life of asset
Total regulatory liabilities		**410**	446	

[a] All regulatory assets and liabilities are excluded from rate base unless otherwise noted.

[b] All or a portion of the balance is included in rate base.

The Company has regulatory assets of $362 million as of December 31, 2014 and $327 million as of December 31, 2013 related to deferred income tax liabilities. Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since substantially all of these timing differences are related to property, plant and equipment costs, recovery of these regulatory assets is expected to occur over the life of those assets.

The Company has regulatory liabilities associated with plant removal costs of $375 million as of December 31, 2014 and $376 million as of December 31, 2013. These regulatory liabilities represent collections from customers under approved rates for future asset removal activities that are expected to occur associated with its regulated facilities. During 2013, the Company revised the assumption regarding the expected future cost of abandoning distribution service pipelines resulting in a decrease to the regulatory liability of $99 million. Refer to note 8 for further details.

In addition, the Company has regulatory assets of $67 million as of December 31, 2014 and regulatory liabilities of $8 million as of December 31, 2013 representing gas cost collections from customers under approved rates that vary from the actual cost of gas for the associated periods. The Company files an application quarterly with the OEB to ensure that customers' rates are updated to reflect published forward-market prices. The difference between the approved and actual cost of gas is deferred for future repayment to or refund from customers.

Rate Related Information

The Company's distribution rates, beginning January 1, 2014 are set under a five-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation,
- rate increases or decreases in the small volume customer classes where average use declines or increases,
- certain adjustments to base rates,
- the continued pass-through of gas commodity, upstream transportation and demand side management costs,
- the additional pass-through of costs associated with major capital investments and certain fuel variances,
- an allowance for unexpected cost changes that are outside of management's control,
- equal sharing of tax changes between the Company and its customers, and
- an earnings sharing mechanism that permits Union Gas to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.

In September 2014, the Company filed an application with the OEB for new rates effective January 1, 2015 pursuant to the above framework. In December 2014, the OEB approved the application with an implementation date of January 1, 2015.

Annual Deferral Account Disposition

In November 2012, the OEB determined that revenues derived from the optimization of upstream transportation contracts in 2011 would be treated as a reduction to gas costs rather than being treated as optimization revenues and included in utility earnings. Optimization revenues had been classified as utility earnings for 2008, 2009 and 2010 and subsequently for 2012 as described in the following paragraph. This decision was appealed to the Ontario Divisional Court on the basis of impermissible retroactive ratemaking. The appeal was dismissed in December 2013. In May 2014, the Company filed a notice of appeal to the Ontario Court of Appeal and a hearing was held in December 2014. A decision from the Ontario Court of Appeal is expected in 2015.

In May 2013, the Company filed an application with the OEB for the annual disposition of the 2012 deferral account balances. A decision on that application was issued by the OEB in March 2014, resulting in a net benefit of $10 million to earnings. The OEB determined, among other things, that revenues derived from the optimization of upstream transportation contracts in 2012 will be treated as optimization revenues and included in utility earnings rather than a reduction to gas costs. As a result, the Company recognized revenue, net of earnings sharing, of $17 million on the Consolidated Statements of Operations and Comprehensive Income in the first quarter of 2014.

Also included within the May 2013 application was a proposal to establish a new deferral clearing variance account to capture differences between deferral balances approved for disposition and amounts prospectively refunded to or recovered from customers and a request to finalize the incentive amounts owing to the Company from the 2011 Demand Side Management (DSM) program. The OEB found in its March 2014 decision that establishing a new deferral clearing variance account was not appropriate under the parameters of the Company's 2008 through 2012 incentive regulation framework, resulting in a charge of $5 million for the over-refund of the 2011 deferral account balances. The OEB also found that certain adjustments were required to the 2011 DSM incentive amounts, resulting in a charge of $2 million. These charges, totaling $7 million, were also recognized on the Consolidated Statements of Operations and Comprehensive Income in the first quarter of 2014.

The resulting balance for the 2012 deferral accounts was a net refund payable to customers of $2 million which was refunded over a six month period that began July 1, 2014.

In May 2014, the Company filed an application with the OEB for the annual disposition of the 2013 deferral account balances, except for the DSM deferral accounts. The combined impact of the 2013 deferral account balances is a payable to customers of approximately $22 million which is primarily reflected as Accounts payable and accrued charges on the Consolidated Balance Sheets at December 31, 2014 and 2013. In October 2014, the OEB approved the balances with no significant impact to the amounts filed. The net payable to customers is being refunded over a six month period that began January 1, 2015.

Demand Side Management

In December 2014, the Company filed an application with the OEB for the disposition of the 2013 DSM deferral and variance account balances. As a result of this application, the Company has a receivable from customers of approximately $10 million. A hearing and decision from the OEB is expected in 2015.

3. Gas Imbalances

The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Consolidated Balance Sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

At December 31, 2014 Accounts receivable, net and Accounts payable and accrued charges include $660 million (2013 - $484 million) related to gas imbalances and gas balancing services.

4. Inventories

Gas in storage includes gas for delivery to customers and for use in the Company's operations. Inventories of materials and supplies are for use in the Company's operations.

($millions)	**December 31, 2014**	December 31, 2013
Gas in storage	**221**	142
Materials and supplies	**18**	18
	239	160

5. Property, Plant and Equipment, net

($millions)	Useful Life	**December 31, 2014**	December 31, 2013
	(years)		
Plant			
Natural gas transmission	32 - 58	**1,819**	1,701
Natural gas distribution	25 - 60	**4,278**	4,094
Storage	10 - 50	**881**	868
Land rights and rights of way	48 - 61	**110**	109
Other buildings and improvements	2 - 42	**51**	49
Equipment	4 - 15	**89**	89
Vehicles	6	**55**	52
Land	—	**77**	46
Construction in progress	—	**167**	89
Software	4 - 10	**77**	68
Other	15 - 18	**23**	22
Total Property, plant and equipment		**7,627**	7,187
Total accumulated depreciation		**2,399**	2,277
Total accumulated amortization		**74**	63
Total Property, plant and equipment, net		**5,154**	4,847

The Company had no capital leases at December 31, 2014 or 2013.

95% of the Company's property, plant and equipment is regulated with estimated useful lives based on rates approved by the OEB. Composite weighted-average depreciation rates were 3.00% for 2014 and 2.99% for 2013.

Amortization expense of intangible assets totalled $17 million in 2014 and $15 million in 2013. Estimated amortization expense for the next five years is as follows:

($millions)	**2015**	**2016**	**2017**	**2018**	**2019**
Estimated amortization expense	16	12	9	6	4

6. Debt and Credit Facilities

Summary of Debt and Related Terms

($millions)		**December 31, 2014**	December 31, 2013
7.90%	1994 Series debentures, due February 24, 2014	**—**	150
11.50%	1990 Series debentures, due August 28, 2015	**150**	150
4.64%	Series 5, due June 30, 2016	**200**	200
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
2.76%	Series 11, due June 2, 2021	**200**	—
4.85%	Series 6, due April 25, 2022	**125**	125
3.79%	Series 10, due July 10, 2023	**250**	250
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9, due June 21, 2041	**300**	300
4.20%	Series 12, due June 2, 2044	**250**	—
Long-term debt principal (including current maturities)		**2,840**	2,540
Less: Unamortized debt discount		**3**	3
Add: Commercial paper		**270**	336
Total debt		**3,107**	2,873
Less: Current maturities of long-term debt		**150**	150
Less: Commercial paper		**270**	336
Total Long-term debt		**2,687**	2,387

The Company's long-term debt is unsecured. Principal repayment requirements on long-term debt are as follows:

($millions)	**Total**	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**
Long-term debt[(a)]	2,840	150	200	125	400	—	1,965

[(a)] Excludes commercial paper of $270 million.

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2014 and 2013, the Company is in compliance with all such covenants.

Total interest expense on long-term debt in 2014 was $159 million (2013 – $155 million).

Available Credit Facility and Restrictive Debt Covenants

			Commercial Paper Debt Outstanding at	
($millions)	**Expiration Date**	**Credit Facility Capacity**	**December 31, 2014**	December 31, 2013
Multi-year syndicated [(a)]	2019	500	**270**	336

[(a)] The credit facility contains a covenant requiring the debt-to-total capitalization ratio, as defined in the agreement, to not exceed 75% and a provision which requires the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 68% at December 31, 2014 (2013 – 67%).

On December 10, 2014, the Company amended the revolving credit agreement. The facility was increased to $500 million and its expiration date was extended to 2019.

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2014 and 2013 there were no letters of credit issued or revolving borrowings outstanding under the revolving credit facility. A majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2014 was 1.22% (2013 – 1.14%). The weighted average days to maturity on outstanding commercial paper as of December 31, 2014 was 12 days (2013 – 10 days).

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2014 and 2013, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or its subsidiary.

Total interest expense on short-term debt in 2014 was $1 million (2013 – $3 million).

7. Preferred Stock

		Outstanding			
	Authorized	**December 31, 2014**	December 31, 2013	**December 31, 2014**	December 31, 2013
	(shares)	*(shares)*		*($millions)*	
Class A	202,072				
5.5% Series A		**47,672**	47,672	**3**	3
6% Series B		**90,000**	90,000	**5**	5
5% Series C		**49,500**	49,500	**2**	2
4.88% Class B, Series 10	Unlimited	**4,000,000**	4,000,000	**100**	100
				110	110

The Class A, Series A and C Preferred stock are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

The Class A, Series B Preferred stock are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preferred stock are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares once every five years commencing January 1, 2014. The holders of the Class B, Series 10 Preferred stock did not exercise their option on January 1, 2014 and their next optional conversion date is January 1, 2019. Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2018.

The Company has an unlimited number of authorized 4.79% Class B, Series 11 Preferred stock. These shares are cumulative and redeemable at $25 per share at the option of the Company, and at the option of the holders, convertible back into Series 10 shares every five years. At December 31, 2014 and December 31, 2013 none of these shares were issued or outstanding.

The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other type of securities other than preferred stock. As these shares are not solely in the control of the Company, they have been classified as temporary equity on the Consolidated Balance Sheets.

8. Asset Retirement Obligations

The Company's AROs relate to the legal obligation to disconnect, purge and cap abandoned pipelines, capping abandoned storage wells, and in some buildings, special handling and disposition of asbestos if it is disturbed.

The Company has non-asbestos AROs which include easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to the non-asbestos ARO because the fair value of the ARO cannot be reasonably estimated. The Company's pipeline system is considered a critical component of its business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term. The Company has determined that sufficient information to estimate the fair value of an ARO is not available because the assets are considered permanent with indeterminate useful lives and that sufficient information is not available to estimate a range of potential settlement dates in order to employ a present value technique to estimate fair value.

AROs are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

During 2013, the Company revised its estimated future cash flow assumptions resulting in an ARO increase of $183 million, with an offsetting increase of $115 million to Property, plant and equipment - cost, and $31 million to Accumulated depreciation and amortization and a decrease of $99 million to Regulatory and other liabilities. The cash flow change assumptions were substantially related to the expected future cost of abandoning distribution service pipelines.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

($millions)	**December 31, 2014**	December 31, 2013
Balance, beginning of year	**328**	143
Accretion expense	**16**	7
Liabilities settled	**(6)**	(5)
Revisions in estimated cash flows	**30**	183
Balance, end of year	**368**	328

9. Stock Based Compensation

The Spectra Energy 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 40 million shares of common stock may be awarded under the 2007 LTIP. Union Gas employees participate in the 2007 LTIP.

Stock based performance awards generally vest over three years at the earliest, if performance metrics are met. Spectra Energy granted 38,200 performance awards in 2014 and 57,200 in 2013, with fair values of U.S. $2 million for 2014 and $2 million for 2013 to Union Gas' employees. The total fair value of the performance awards vested was U.S. $1 million in 2014 and 2013. As of December 31, 2014, the Company expects to recognize U.S. $2 million of future compensation cost related to performance awards over a weighted-average period of less than one year.

Stock based phantom awards generally vest over three years. Spectra Energy awarded 24,200 phantom awards in 2014 and 36,400 in 2013, with fair values of U.S. $1 million for both 2014 and 2013 to Union Gas' employees. The total fair value of the phantom awards vested was U.S. $1 million in both 2014 and 2013. As of December 31, 2014, the Company expects to recognize U.S. $1 million of future compensation cost related to phantom awards over a weighted-average period of less than two years.

	Performance Awards		**Phantom Awards**	
	Units	**Weighted-Average Grant Date Fair Value U.S. $**	**Units**	**Weighted-Average Grant Date Fair Value U.S. $**
Outstanding, beginning of year	142,008	39	95,617	29
Transfers out	(7,600)	38	(12,200)	27
Granted	38,200	46	24,200	37
Vested	(38,598)	33	(26,253)	26
Forfeited	(7,491)	39	(2,492)	33
Outstanding, end of year	126,519	35	78,872	32
Awards expected to vest	124,609	35	77,657	32

10. Fair Value Measurements

Financial instruments recorded at fair value on the Consolidated Balance Sheets are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of the Company's financial instruments that are actively traded in the secondary market are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency. The fair value of the Company's pension plan assets designated as Level 2 financial instruments is determined through the market approach valuation technique using observable inputs including matrix pricing and market corroborated pricing.

Level 3 Valuation Techniques

Level 3 valuation techniques include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation. The fair value of the Company's pension plan assets designated as Level 3 financial instruments is determined through the market approach valuation technique using unobservable inputs including investment manager pricing for private placements and private equities.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts that could have been realized in current markets.

	December 31, 2014		December 31, 2013	
($millions)	**Book Value**	**Fair Value**	Book Value	Fair Value
Long-term debt, including current maturities[a]	**2,840**	**3,323**	2,540	2,877

[a] Excludes unamortized items.

The fair value of the Company's Long-term debt is determined based on market-based prices as described in the Level 2 valuation technique described above.

The fair values of Cash and cash equivalents, Accounts receivable, net, Accounts payable and accrued charges, Short-term borrowings and Commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligation. The maximum exposure to credit risk of the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement amount of gas loans at December 31, 2014 is $102 million receivable (2013 – $132 million receivable). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

The Company manages its credit risk on Cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on Accounts receivable, net the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2014 amounted to $37 million (2013 – $35 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

The Company continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31, 2014**	December 31, 2013
Current	**316**	300
30 Days over due	**13**	11
60 Days over due	**5**	4
90+ Days over due	**12**	7
Total trade accounts receivable	**346**	322
Allowance for doubtful accounts	**(6)**	(6)
Total trade accounts receivable, net[a]	**340**	316

[a] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

For the years ended December 31, 2014 and 2013, no one customer accounted for more than 10% of sales or 10% of receivables.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 6).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2014:

($millions)	**Total**	**2015**	**2016-2017**	**2018-2019**	**Thereafter**
Commercial paper	270	270	—	—	—
Accounts payable and accrued charges	1,117	1,117	—	—	—
Long-term debt (including principal and interest)	4,931	308	603	609	3,411
Total	6,318	1,695	603	609	3,411

11. Employee Benefit Plans

Retirement Plans

The Company maintains registered and non-registered, contributory and non-contributory defined benefit (DB Plans) and defined contribution (DC Plan) retirement plans covering substantially all employees. The DB Plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC Plan, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings. The Company also provides non-registered DB Plans to all employees who retire under a registered DB Plan and whose pension is limited by the maximum pension limits under the Income Tax Act.

The Company's policy is to fund the retirement plans, where applicable, on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. Total contributions to the DB Plans were $18 million in 2014 and $54 million in 2013. Contributions of $6 million in both 2014 and 2013 were made to the Company's DC Plan. The Company anticipates that in 2015 it will make total contributions of approximately $11 million to its DB Plans and $6 million to its DC Plan.

Actuarial gains and losses are amortized over the average remaining service period of active employees. The average remaining service periods of active employees covered by the registered and non-registered DB Plans is 10 years. The Company determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over three years.

Registered and Non-Registered Pension Plans

Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

($millions)	**2014**	2013
Change in Projected Benefit Obligation		
Projected benefit obligation, beginning of year	**748**	787
Service cost	**15**	20
Interest cost	**35**	32
Actuarial loss (gain)	**98**	(60)
Participant contributions	**3**	3
Benefits paid	**(36)**	(34)
Projected benefit obligation, end of year	**863**	748
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**761**	658
Actual return on plan assets	**86**	80
Benefits paid	**(36)**	(34)
Employer contributions	**18**	54
Plan participants' contributions	**3**	3
Expected non-investment expenses	**(3)**	—
Plan assets, end of year	**829**	761
Net amount recognized[a]	**(34)**	13
Accumulated Benefit Obligation	**812**	707

[a]At December 31, 2014 the Consolidated Balance Sheets includes $5 million of non-current pension assets recognized in Regulatory and other assets, $37 million of non-current pension liabilities in Regulatory and other liabilities, and $2 million of current pension liabilities in Accounts payable and accrued charges.

The table above includes non-registered pension plans that are not funded and had projected benefit obligations of $39 million at December 31, 2014 and $34 million at December 31, 2013. At December 31, 2014 there were no registered DB plans with accumulated benefit obligations in excess of plan assets. Non-registered DB plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations of $39 million and accumulated benefit obligations of $36 million.

Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)

($millions)	**December 31, 2014**	December 31, 2013
Net actuarial loss	**256**	210
Prior service costs	**5**	6
Total amounts recognized in AOCI, pre-tax	**261**	216

Components of Net Periodic Pension Costs

($millions)	**2014**	2013
Net Periodic Pension Cost		
Service cost benefit earned	**18**	20
Interest cost on projected benefit obligation	**35**	32
Expected return on plan assets	**(52)**	(47)
Amortization of prior service cost	**1**	2
Amortization of loss	**18**	25
Net periodic pension cost	**20**	32
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial (gain) loss	**64**	(93)
Amortization of actuarial loss	**(18)**	(25)
Amortization of prior service cost	**(1)**	(2)
Total recognized in other comprehensive income	**45**	(120)
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	**65**	(88)

At December 31, 2014, approximately $22 million of actuarial losses will be amortized from AOCI on the Consolidated Balance Sheets into net periodic pension cost in 2015.

At December 31, 2014, approximately $1 million of prior service costs will be amortized from AOCI on the Consolidated Balance Sheets into net periodic pension costs in 2015.

Assumptions Used for Pension Benefits Accounting

	2014	2013
Benefit Obligations		
Discount rate	**4.00%**	4.81%
Salary increase	**3.25%**	3.25%
Net Periodic Benefit Cost		
Discount rate	**4.81%**	4.15%
Salary increase	**3.25%**	3.25%
Expected long-term rate of return on plan assets	**7.40%**	7.10%

The discount rates used to determine the benefit obligations are the rates at which the benefit obligations could be effectively settled. The discount rates are developed from yields on available high-quality bonds and reflect each plan’s expected cash flows.

The long-term rates of return for the plan assets in 2014 were developed using weighted-average calculations of expected returns based primarily on future expected returns across classes considering the use of active asset managers applied against the plans’ respective targeted asset mix.

Registered Pension Plan Assets

Asset Category	Target Allocation	**December 31, 2014**	December 31, 2013
U.S. equity securities	17%	**17%**	18%
Canadian equity securities	25%	**25%**	26%
Other equity securities	13%	**13%**	13%
Fixed income securities	45%	**45%**	43%
Total	100%	**100%**	100%

Pension plan assets are maintained in a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. The Company regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The following table summarizes the fair values of pension plan assets recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in note 10:

($millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
December 31, 2014				
Cash and cash equivalents	2	2	—	—
Fixed income securities	372	372	—	—
Equity securities	455	270	185	—
Total	829	644	185	—
December 31, 2013				
Cash and cash equivalents	4	4	—	—
Fixed income securities	324	324	—	—
Equity securities	433	314	119	—
Total	761	642	119	—

Expected Benefit Payments

($millions)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020-2024**
Expected benefit payments	40	42	44	46	47	255

Other Post-Retirement Benefit Plans

The Company provides health care and life insurance benefits for retired employees on a non-contributory basis predominantly under defined contribution plans. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The other post-retirement benefit plans are not funded.

Other Post-Retirement Benefit Plans - Change in Projected Benefit Obligation and Fair Value of Plan Assets

($millions)	**2014**	2013
Change in Benefit Obligation		
Accumulated post-retirement benefit obligation, beginning of year	**64**	67
Service cost	**1**	2
Interest cost	**3**	3
Actuarial gain	**1**	(5)
Benefits paid	**(2)**	(3)
Accumulated post-retirement benefit obligation, end of year	**67**	64
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**—**	—
Benefits paid	**(2)**	(3)
Employer contributions	**2**	3
Plan assets, end of year	**—**	—
Net amount recognized[a]	**(67)**	(64)

[a] $64 million is recognized in Regulatory and other liabilities and $3 million is recognized in Accounts payable and accrued charges on the Consolidated Balance Sheets.

Other Post-Retirement Benefit Plans - Amounts Recognized in AOCI

($millions)	**December 31, 2014**	December 31, 2013
Net actuarial loss recognized in AOCI	**4**	3

($millions)	**2014**	2013
Other Post-Retirement Benefit Plans - Components of Net Periodic Benefit Cost		
Service cost benefit earned	**1**	2
Interest cost on accumulated post-retirement benefit obligation	**3**	3
Net periodic other post-retirement benefit cost	**4**	5
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial gain	**1**	(5)
Total recognized in other comprehensive income	**1**	(5)
Total recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**5**	—

Other Post-Retirement Benefits Plans - Assumptions Used for Benefits Accounting

	2014	2013
Benefit Obligations		
Discount rate for post-retirement plans	**4.00%**	4.83%
Salary increase	**3.25%**	3.25%
Net Periodic Benefit Cost		
Discount rate for post-retirement plans	**4.83%**	4.20%
Salary increase	**3.25%**	3.25%

The discount rates used to determine the post-retirement obligations are the rates at which the benefit obligations could be effectively settled. The discount rates for the plans are developed from yields on available high-quality bonds in Canada and reflect each plan's expected cash flows.

Assumed Health Care Cost Trend Rates

	2014	2013
Health care cost trend rate assumed for next year	**6.00%**	6.50%
Rate to which the cost trend rate is assumed to decline	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**2017**	2017

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

($millions)	**1% Point Increase**	1% Point Decrease
Effect on total service and interest costs	**1**	—
Effect on post-retirement benefit obligations	**5**	(4)

Other Post-Retirement Benefit Plans - Payments and Receipts

The Company expects to make future benefit payments, which reflect expected future service, as appropriate. The following benefit payments are expected to be paid over each of the next five years and thereafter.

($millions)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020-2024**
Expected benefit payments	3	3	3	3	4	19

Savings Plan

The Company has employee savings plans available to eligible employees. Employees may participate in a matching contribution where the Company matches a certain percentage of before-tax employee contributions of up to 5% of eligible pay per pay period. The Company expensed pre-tax employer matching contributions of $8 million in both 2014 and 2013.

12. Income Taxes

Income Tax Expense Components

($millions)	**2014**	2013
Current		
Federal	**16**	12
Provincial	**7**	6
Total current tax expense	**23**	18
Deferred		
Federal	**7**	2
Provincial	**6**	1
Total deferred tax expense	**13**	3
Total Income taxes	**36**	21

Reconciliation of Income Tax Expense at the Combined Federal and Ontario Statutory Tax Rate to Actual Income Tax Expense

($millions)	**2014**	2013
Income before income taxes	**231**	228
Statutory income tax rate	**26.5%**	26.5%
Statutory income tax rate applied to accounting income	**61**	60
Increase/(decrease) resulting from:		
Enacted Canadian federal income tax legislation[a]	—	(16)
Deferred income tax adjustments related to rate regulated operations	**(27)**	(23)
Other - net	**2**	—
Total income tax expense	**36**	21
Effective rate of income tax	**15.6%**	9.2%

[a] Due to the recognition of tax benefits associated with favourable Canadian federal income tax legislation enacted on June 26, 2013 (Enacted Legislation). The Enacted Legislation contained changes that resulted in increased tax deductions and has a beneficial impact for the tax years 2008 and forward.

Net Deferred Income Tax Liability Components

($millions)	**December 31, 2014**	December 31, 2013
Deferred income tax liabilities		
Accelerated depreciation rates	**344**	328
Regulatory asset	**94**	86
Reserves	**27**	—
Other	**(23)**	(6)
Total deferred income tax liabilities	**442**	408
Deferred income tax assets		
Regulatory liability	—	2
Other	—	1
Total deferred income tax assets	—	3
Net deferred income tax liabilities	**442**	405

The above deferred tax amounts have been classified in the Consolidated Balance Sheets as follows:

($millions)	**December 31, 2014**	December 31, 2013
Current liabilities	**(25)**	3
Long-term liabilities	**(417)**	(408)
	(442)	(405)

Reconciliation of Gross Unrecognized Income Tax Benefits

($millions)	**December 31, 2014**	December 31, 2013
Balance, beginning of year	**11**	26
Increases related to prior year tax positions	**9**	2
Decreases related to prior year tax positions	**—**	(13)
Increases related to current year tax positions	**2**	1
Audit settlements	**—**	(1)
Reductions due to lapse of statute of limitations	**(3)**	(4)
Balance, end of year	**19**	11

Unrecognized tax benefits totalled $19 million at December 31, 2014. Of this, $14 million would reduce the effective tax rate if recognized on or after January 1, 2015. The Company recorded an increase of $8 million in gross unrecognized tax benefits during 2014. This resulted in an $8 million increase in tax expense.

The Company recognized potential accrued interest related to unrecognized tax benefits as interest expense. A $1 million benefit was recorded to interest expense in 2014 compared to a $2 million expense in 2013. Accrued interest totalled $2 million at December 31, 2014 and $2 million at December 31, 2013.

Although uncertain, the Company believes it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $12 million prior to December 31, 2015. The anticipated changes in unrecognized tax benefits relate to the expiration of statutes of limitations and expected audit settlements.

The Company remains subject to examination for income tax returns for years 2009 through 2013.

13. Related Party Transactions

The Company purchases gas and storage services at prevailing market prices and under normal trade terms from related parties. During 2014, these purchases totalled $140 million (2013 – $83 million). The Company also provides storage and transportation services to related parties which totalled $1 million during 2014 (2013 – $1 million).

The Company provided administrative, management and other services to related parties totalling $17 million during 2014 (2013 – $13 million), which were billed and recovered at cost. Charges from related parties for administrative and other goods and services were $17 million during 2014 (2013 – $11 million).

At December 31, 2014 the Company had receivable balances of $10 million (2013 – $5 million) and payable balances of $14 million (2013 – $29 million) with related parties, all of which are recorded in Accounts receivable, net and Accounts payable and accrued charges, respectively.

In the normal course of operations, the Company provides or obtains funds from Westcoast on an unsecured basis. The balance outstanding at December 31, 2014 was a payable of $48 million (2013 – $nil). During 2014, interest paid on these loans totalled less than $1 million (2013 – less than $1 million) and interest received on these loans totalled less than $1 million (2013 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

The Company also has a promissory note to borrow up to $150 million from GLBE on an unsecured basis. Funds from this promissory note are used for general corporate purposes. There was no balance outstanding at December 31, 2014 or 2013.

In addition, beginning in 2014, the Company declared and paid a common stock dividend on an annual rather than quarterly basis. For 2014, the Company paid dividends to GLBE of $100 million (2013 – $149 million).

14. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company's potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

15. Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated. The Company has no reason to believe that the ultimate outcome of these matters could have a significant impact on its Consolidated Financial Statements.

16. Subsequent Events

On January 30, 2015, Union Gas purchased the remaining 25% of HTLP. Total consideration for the transaction consisted of $2.25 million in cash. This purchase resulted in an increase to Paid-in Capital of approximately $6 million ($4 million net of tax) and a decrease to Non-controlling interest of approximately $8 million.

Management has evaluated significant events and transactions that occurred from January 1, 2015 through March 6, 2015, the date the financial statements were filed, and no other subsequent events requiring disclosure were noted.

DIRECTORS

David G. Unruh
Stephen W. Baker
Bruce E. Pydee

OFFICERS

Stephen W. Baker
Chair and President

J. Patrick Reddy
Chief Financial Officer

M. Richard Birmingham
Vice President, Regulatory, Lands and Public Affairs

Bruce E. Pydee
Vice President and General Counsel

Janice L. Ferguson
Vice President, Human Resources

Mark J. Isherwood
Vice President, Business Development - Storage and Transmission

Paul Rietdyk
Vice President, Engineering and Construction and Storage and Transmission Operations

Michael P. Shannon
Vice President, Distribution Operations

Wendy Zelond
Vice President, Finance

Laura J. Sayavedra
Vice President and Treasurer

Timothy J. Kennedy
Vice President, Government and Aboriginal Affairs

David G. Simpson
Vice President, In-Franchise Sales, Marketing and Customer Care

Paul K. Haralson
Assistant Treasurer

Patricia M. Rice
Corporate Secretary

Leigh A. Hodgins
Assistant Secretary

Tanya Mushynski
Assistant Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **CST Trust Company**

Union Gas Limited preferred stock are listed on the Toronto Stock Exchange
Class A Preferred, Series A - 5½% (UNG.PR.C)

Class A Preferred, Series B - 6% (UNG.PR.D)

REGISTERED OFFICE

50 Keil Drive North
Chatham, Ontario N7M 5M1

The Financial Statements and all information in this report have been prepared by and are the responsibility of management. The Financial Statements have been prepared in conformity with generally accepted accounting principles in the United States of America and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon Union Gas Limited's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors (the Board) is responsible for ensuring that management fulfils its responsibility for financial reporting and for final approval of the Financial Statements.

The Board meets regularly with management, the internal auditors and the shareholders' auditors to review the Financial Statements, the Independent Auditor's Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Board, as does the Director of Internal Audit Services.

Deloitte LLP performed an independent audit of the 2015 and 2014 Financial Statements in this report. Their independent professional opinion on the fairness of these Financial Statements is included in the Independent Auditor's Report.

March 3, 2016

Stephen W. Baker	J. Patrick Reddy
President	Chief Financial Officer

Deloitte.

Deloitte LLP
150 Ouellette Place
Suite 200
Windsor ON N8X 1L9
Canada

Tel: 519-967-0388
Fax: 519-967-0324
www.deloitte.ca

Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying financial statements of Union Gas Limited, which comprise the balance sheets as at December 31, 2015 and December 31, 2014, and the statements of operations and comprehensive income, statements of equity, and statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2015 and December 31, 2014, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Deloitte LLP

Chartered Professional Accountants
Licensed Public Accountants
March 1, 2016

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the Years Ended December 31 ($millions)	**2015**	2014
Gas sales and distribution revenue	**1,675**	1,755
Cost of gas (note 9)	**875**	977
Gas distribution margin	**800**	778
Storage and transportation revenue (note 9)	**239**	266
Other revenue, net	**26**	21
Net operating revenue	**1,065**	1,065
Expenses		
Operating and maintenance (note 9)	**399**	397
Depreciation and amortization	**224**	212
Property taxes and other	**69**	69
Total expenses	**692**	678
Income before interest and income taxes	**373**	387
Interest expense (notes 9 and 10)	**157**	156
Income before income taxes	**216**	231
Income tax expense (note 6)	**28**	36
Net income	**188**	195
Preferred stock dividends	**3**	3
Net income applicable to common stock	**185**	192
Other comprehensive income, net of tax		
Pension and benefits impact (net of tax of 6 and (12) respectively) (note 12)	**16**	(33)
Comprehensive income applicable to common stock	**201**	159

(See accompanying notes)

BALANCE SHEETS

As at December 31 ($millions)	**2015**	2014
Assets		
Current assets		
Cash and cash equivalents	**5**	20
Accounts receivable, net (notes 4 and 9)	**650**	1,135
Income taxes receivable (note 6)	**24**	17
Inventories (note 5)	**297**	239
Total current assets	**976**	1,411
Property, plant and equipment (note 7)		
Cost	**8,300**	7,627
Accumulated depreciation and amortization	**(2,622)**	(2,473)
Property, plant and equipment, net	**5,678**	5,154
Regulatory and other assets (notes 3 and 8)	**536**	469
Total Assets	**7,190**	7,034
Liabilities and Equity		
Current liabilities		
Short-term borrowings (note 9)	**56**	48
Commercial paper (note 10)	**207**	270
Accounts payable and accrued charges (notes 4 and 9)	**793**	1,117
Current maturities of long-term debt (note 10)	**200**	150
Deferred income taxes (note 6)	**—**	25
Total current liabilities	**1,256**	1,610
Long-term liabilities		
Long-term debt (note 10)	**2,921**	2,676
Deferred income taxes (note 6)	**451**	417
Asset retirement obligations (note 13)	**440**	368
Regulatory and other liabilities (notes 3 and 8)	**509**	497
Total long-term liabilities	**4,321**	3,958
Total Liabilities	**5,577**	5,568
Preferred Stock (note 11)	**110**	110
Equity		
Common stock, unlimited shares authorized, 57,822,650 outstanding	**627**	627
Retained earnings	**1,051**	916
Accumulated other comprehensive loss	**(179)**	(195)
Paid-in capital (note 2)	**4**	—
Non-controlling interest (note 2)	**—**	8
Total Equity	**1,503**	1,356
Total Liabilities and Equity	**7,190**	7,034

(See accompanying notes)

Approved by the Board

Director

Director

STATEMENTS OF CASH FLOWS

For the Years Ended December 31 ($millions)	**2015**	2014
Operating Activities		
Net income	**188**	195
Items not affecting cash		
Depreciation and amortization	**224**	212
Loss on disposal of assets	**—**	1
Deferred income taxes	**(40)**	13
Changes in working capital		
Accounts receivable	**89**	(89)
Inventories	**(60)**	(112)
Accounts payable, accrued charges and other	**100**	85
Net cash provided by operating activities	**501**	305
Investing Activities		
Capital expenditures	**(701)**	(474)
Financing Activities		
Net increase in short-term borrowings	**8**	48
Net decrease in commercial paper	**(63)**	(66)
Long-term debt issued	**445**	450
Long-term debt repayments	**(150)**	(150)
Purchase of subsidiary shares from non-controlling interest	**(2)**	—
Dividends paid	**(53)**	(103)
Net cash provided by financing activities	**185**	179
Change in cash and cash equivalents, during the year	**(15)**	10
Cash and cash equivalents, beginning of year	**20**	10
Cash and cash equivalents, end of year	**5**	20
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest, net of amounts capitalized	**160**	160
Cash payments of income taxes, net of refunds received	**66**	26

(See accompanying notes)

STATEMENTS OF EQUITY

($millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Paid-in Capital	Non-controlling Interest	Total
December 31, 2014	627	916	(195)	—	8	1,356
Net income	—	188	—	—	—	188
Other comprehensive income	—	—	16	—	—	16
Dividends						
Preferred stock	—	(3)	—	—	—	(3)
Common stock	—	(50)	—	—	—	(50)
Purchase of subsidiary shares from non-controlling interest	—	—	—	4	(8)	(4)
December 31, 2015	627	1,051	(179)	4	—	1,503
December 31, 2013	627	824	(162)	—	9	1,298
Net income	—	195	—	—	—	195
Other comprehensive income	—	—	(33)	—	—	(33)
Dividends						
Preferred stock	—	(3)	—	—	—	(3)
Common stock	—	(100)	—	—	—	(100)
Other	—	—	—	—	(1)	(1)
December 31, 2014	627	916	(195)	—	8	1,356

(See accompanying notes)

UNION GAS LIMITED
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2015 AND 2014

1. Summary of Operations and Significant Accounting Policies

The terms "Union Gas" or "the Company" as used in these Financial Statements refer to Union Gas Limited unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. Union Gas' common stock is held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

Nature of Operations

Union Gas owns and operates natural gas distribution, storage and transmission facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy market participants. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the distribution, storage and transportation of natural gas.

Basis of Presentation

The Financial Statements of the Company include the standalone accounts of the Company. On June 1, 2015 the Company dissolved its subsidiary, Huron Tipperary Limited Partnership I (HTLP), transferring HTLP's assets and liabilities to the Company with no material financial impact to the Company. Comparative figures for 2014 are shown consolidated with HTLP.

The Financial Statements of the Company have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). All amounts are presented in millions of Canadian dollars except where noted.

In 2014, Canadian securities regulators approved the extension of the Company's exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

Use of Estimates

The preparation of the Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual amounts could differ from these estimates.

Regulation

The Company is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act, (1998)*. This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within the Company and provides the framework required to support new storage investments.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and its ability to achieve forecasted revenues and manage costs.

Effective January 1, 2014, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts.

As part of the Company's OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings in excess of 100 basis points above the allowable return on equity are shared with ratepayers as a reduction in earnings during the year, if applicable.

The Company follows U.S. GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered and collection is reasonably assured. Revenues related to these services provided or products delivered but not yet billed are estimated each month.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred on the Balance Sheets for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the cost of gas an estimated amount of these differences based upon the methodology used by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Income Taxes

Deferred income taxes are recognized for differences between the financial reporting and tax bases of assets and liabilities at enacted statutory tax rates in effect for the years in which the differences are expected to reverse. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Actual income taxes could vary from these estimates due to the future changes in income tax law or results from the final review of tax returns by federal and provincial tax authorities.

Financial statement effects on tax positions are recognized in the period in which it is more likely than not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest related to the unrecognized tax benefits is recorded as Interest expense on the Statements of Operations and Comprehensive Income.

Inventories

Gas in storage for resale to customers is carried at weighted average cost approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred on the Balance Sheets for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment is stated at historical cost less accumulated depreciation and amortization. The Company capitalizes all construction-related direct labour and material costs, as well as indirect construction costs. Indirect costs include general engineering and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred.

Regulated depreciation is computed based on the asset's average service life using the straight-line method. Unregulated depreciation is computed based on management's assumption of useful life using the straight-line method.

When regulated property, plant and equipment is retired, the original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation and amortization. When entire regulated operating units are sold or non-regulated property, plant and equipment is retired, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Asset Retirement Obligations (AROs)

The Company recognizes AROs for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within the Company's control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

Stock-Based Compensation

Union Gas employees participate in a stock-based compensation plan sponsored by Spectra Energy. For employee awards, equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests, the date the employee becomes retirement-eligible, or the date the award market condition is met. Awards, including stock options, granted to employees that are already retirement-eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

Pension and Other Post-Retirement Benefits

The Company fully recognizes the overfunded or underfunded status of pension and other post-retirement benefit plans as Regulatory and other assets, Accounts payable and accrued charges, or Regulatory and other liabilities on the Balance Sheets. A plan's funded status is the difference between the fair value of plan assets and the plan's benefit obligation. The Company records deferred plan costs and income (unrecognized losses and gains, and unrecognized prior service costs and credits) in Accumulated other comprehensive loss, until they are amortized to be recognized as a component of benefit expense within Operating and maintenance expenses in the Statements of Operations and Comprehensive Income. See note 12 for further discussion.

New Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-03, "*Interest-Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*", which requires that debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability, rather than as a deferred charge asset. The Company adopted this standard on December 31, 2015. The adoption of this ASU resulted in the retrospective adjustment of the December 31, 2014 Balance Sheet, which resulted in the presentation of $11 million of debt issuance costs previously reported in Regulatory and other assets as a reduction to Long-term debt. In addition, $12 million of debt issuance costs are presented as a reduction of Long-term debt on the Company's December 31, 2015 Balance Sheet.

In July 2015, the FASB issued ASU No. 2015-11, "*Inventory (Topic 330): Simplifying the Measurement of Inventory*", which simplifies the subsequent measurement of inventory by requiring inventory to be measured at the lower of cost and net realizable value. This ASU is effective for the Company January 1, 2016 and is not expected to have a material impact on the Company's Financial Statements.

In July 2015, the FASB decided to defer the effective date of the revenue standard ASU No. 2014-09, "*Revenue from Contracts with Customers (Topic 606),*" for one year and to permit entities to early adopt the standard as of the original effective date. ASU No. 2014-09 supersedes the revenue recognition requirements of "*Revenue Recognition (Topic 605)*" and clarifies the principles of recognizing revenue. This ASU is effective for the Company January 1, 2018. The Company is currently evaluating this ASU and its potential impact.

In November 2015, the FASB issued ASU No. 2015-17, "*Accounting for Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes."* This ASU simplifies the balance sheet presentation of deferred income taxes by requiring deferred tax liabilities and assets be classified as noncurrent in a classified balance sheet. The Company adopted this standard on December 31, 2015 and applied it prospectively. The adoption of this ASU did not have a material impact on the Company's Financial Statements.

In January 2016, the FASB issued ASU 2016-01, "*Financial Instruments--Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities,*" which amends the classification and measurement of financial instruments. Changes primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. This ASU is effective for the Company beginning after December 15, 2017. Early adoption is not permitted. The Company is currently evaluating this ASU and its potential impact.

2. Acquisitions

On January 30, 2015, Union Gas purchased the remaining 25% of HTLP. Total consideration for the transaction consisted of $2.25 million in cash. This purchase resulted in an increase to Paid-in capital of approximately $6 million ($4 million net of tax) and a decrease to Non-controlling interest of approximately $8 million. The Company dissolved HTLP on June 1, 2015 which did not have a significant impact to the Company's Financial Statements.

3. Regulatory Matters

Regulatory Assets and Liabilities

The Company recorded the following assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	**December 31, 2015**	December 31, 2014	Recovery/Settlement Period
Regulatory assets[a]				
Customer deferrals	Accounts receivable, net	**43**	42	Less than 1 year
Gas cost deferrals	Accounts receivable, net	**—**	67	Less than 1 year
Gas in storage inventory	Inventories	**53**	8	Less than 1 year
Other deferrals – long-term	Regulatory and other assets	**—**	1	2 – 3 years
Deferred income taxes – long-term[b]	Regulatory and other assets	**403**	362	2 years – remaining life of asset
Total regulatory assets		**499**	480	
Regulatory liabilities[a]				
Other deferrals – current[b]	Accounts payable and accrued charges	**7**	7	Less than 1 year
Customer deferrals	Accounts payable and accrued charges	**1**	28	Less than 1 year
Gas cost deferrals	Accounts payable and accrued charges	**67**	—	Less than 1 year
Asset removal costs[b]	Regulatory and other liabilities	**357**	375	Exceeds remaining life of asset
Total regulatory liabilities		**432**	410	

[a] All regulatory assets and liabilities are excluded from rate base unless otherwise noted.

[b] All or a portion of the balance is included in rate base.

The Company has regulatory assets of $403 million as of December 31, 2015 and $362 million as of December 31, 2014 related to deferred income tax liabilities. Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since substantially all of these timing differences are related to property, plant and equipment costs, recovery of these regulatory assets is expected to occur over the life of those assets.

The Company has regulatory liabilities associated with plant removal costs of $357 million as of December 31, 2015 and $375 million as of December 31, 2014. These regulatory liabilities represent collections from customers under approved rates for future asset removal activities that are expected to occur associated with its regulated facilities.

In addition, the Company has regulatory liabilities of $67 million as of December 31, 2015 and regulatory assets of $67 million as of December 31, 2014 representing gas cost collections from customers under approved rates that vary from the actual cost of gas for the associated periods. The Company files an application quarterly with the OEB to ensure that customers' rates are updated to reflect published forward-market prices. The difference between the approved and actual cost of gas is deferred for future repayment to or refund from customers.

Rate Related Information

The Company's distribution rates, beginning January 1, 2014 are set under a five-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation,
- rate increases or decreases in the small volume customer classes where average use declines or increases,
- certain adjustments to base rates,
- the continued pass-through of gas commodity, upstream transportation and demand side management costs,
- the additional pass-through of costs associated with major capital investments and certain fuel variances,
- an allowance for unexpected cost changes that are outside of management's control,
- equal sharing of tax changes between the Company and its customers, and
- an earnings sharing mechanism that permits the Company to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.

Demand Side Management (DSM)

In December 2015, the Company filed an application with the OEB for the disposition of the 2014 DSM deferral and variance account balances. As a result of this application, the Company has a receivable from customers of approximately $11 million which is reflected as Accounts receivable, net on the Balance Sheets at December 31, 2015 and December 31, 2014. A hearing and decision from the OEB is expected in 2016.

4. Gas Imbalances

The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Balance Sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

At December 31, 2015 Accounts receivable, net and Accounts payable and accrued charges include $350 million (2014 - $660 million) related to gas imbalances and gas balancing services.

5. Inventories

Gas in storage includes gas for delivery to customers and for use in the Company's operations. Inventories of materials and supplies are for use in the Company's operations.

($millions)	**December 31, 2015**	December 31, 2014
Gas in storage	**279**	221
Materials and supplies	**18**	18
	297	239

6. Income Taxes

Income Tax Expense Components

($millions)	**2015**	2014
Current		
Federal	**43**	16
Provincial	**25**	7
Total current tax expense	**68**	23
Deferred		
Federal	**(24)**	7
Provincial	**(16)**	6
Total deferred tax expense	**(40)**	13
Total Income taxes	**28**	36

Reconciliation of Income Tax Expense at the Combined Federal and Ontario Statutory Tax Rate to Actual Income Tax Expense

($millions)	**2015**	2014
Income before income taxes	**216**	231
Statutory income tax rate	**26.5%**	26.5%
Statutory income tax rate applied to accounting income	**57**	61
Increase/(decrease) resulting from:		
Deferred income tax adjustments related to rate regulated operations	**(33)**	(27)
Other - net	**4**	2
Total income tax expense	**28**	36
Effective rate of income tax	**13.0%**	15.6%

Net Deferred Income Tax Liability Components

($millions)	**December 31, 2015**	December 31, 2014
Deferred income tax liabilities		
Accelerated depreciation rates	**370**	344
Regulatory asset	**105**	94
Reserves	**(1)**	27
Other	**(23)**	(23)
Total deferred income tax liabilities	**451**	442

The above deferred tax amounts have been classified in the Balance Sheets as follows:

($millions)	**December 31, 2015**	December 31, 2014
Current liabilities	—	(25)
Long-term liabilities	**(451)**	(417)
	(451)	(442)

Reconciliation of Gross Unrecognized Income Tax Benefits

($millions)	**December 31, 2015**	December 31, 2014
Balance, beginning of year	**19**	11
Increases related to prior year tax positions	**11**	9
Increases related to current year tax positions	**2**	2
Reductions due to lapse of statute of limitations	**(4)**	(3)
Balance, end of year	**28**	19

Unrecognized tax benefits totalled $28 million at December 31, 2015. Of this, $26 million would reduce the effective tax rate if recognized on or after January 1, 2016. The Company recorded a net increase of $9 million in gross unrecognized tax benefits in 2015. This was a result of $4 million attributable to deferred tax liability and $13 million increase in income tax expense.

The Company recognized potential accrued interest related to unrecognized tax benefits as interest expense. A $1 million benefit was recorded to interest expense in 2015 compared to a $1 million benefit in 2014. Accrued interest totalled $1 million at December 31, 2015 and $2 million at December 31, 2014.

Although uncertain, the Company believes it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $20 million prior to December 31, 2016. The anticipated changes in unrecognized tax benefits relate to the expiration of statutes of limitations and expected audit settlements.

The Company remains subject to examination for income tax returns for years 2009 through 2014.

7. Property, Plant and Equipment, net

($millions)	Useful Life	**December 31, 2015**	December 31, 2014
	(years)		
Plant			
Natural gas transmission	32 - 58	**2,210**	1,819
Natural gas distribution	25 - 60	**4,494**	4,278
Storage	10 - 50	**887**	881
Land rights and rights of way	48 - 61	**120**	110
Other buildings and improvements	2 - 42	**62**	51
Equipment	4 - 15	**86**	89
Vehicles	6	**56**	55
Land	—	**78**	77
Construction in progress	—	**193**	167
Software	4 - 10	**89**	77
Other	15 - 18	**25**	23
Total Property, plant and equipment		**8,300**	7,627
Total accumulated depreciation		**2,545**	2,399
Total accumulated amortization		**77**	74
Total Property, plant and equipment, net		**5,678**	5,154

The Company had no capital leases at December 31, 2015 or 2014.

95% of the Company's property, plant and equipment is regulated with estimated useful lives based on rates approved by the OEB. Composite weighted-average depreciation rates were 2.97% for 2015 and 3.00% for 2014.

The Company capitalized interest of $7 million in 2015 and $4 million in 2014.

Amortization expense of intangible assets totaled $18 million in 2015 and $17 million in 2014. Estimated amortization expense for the next five years is as follows:

($millions)	**2016**	**2017**	**2018**	**2019**	**2020**
Estimated amortization expense	16	13	10	7	6

8. Regulatory and Other Assets and Liabilities

($millions)	**December 31, 2015**	December 31, 2014
Regulatory assets	**403**	363
Goodwill	**12**	12
Pension assets	**28**	5
Gas balancing	**67**	69
Material and supplies	**10**	9
Deposits on projects	**14**	10
Other	**2**	1
Total Regulatory and other assets	**536**	469
Regulatory liabilities	**357**	375
Pension liabilities	**122**	101
Unrecognized tax benefits	**28**	19
Other	**2**	2
Total Regulatory and other liabilities	**509**	497

9. Related Party Transactions

The Company occasionally perform services for and incur costs on behalf of the Company's affiliates, which are subsequently reimbursed. Likewise, certain affiliates may perform services for or incur costs on behalf of the Company, which are then reimbursed by the Company. These transactions are in the normal course of operations and are recorded at exchange amounts agreed to between the related parties.

In addition, Spectra Energy and its affiliates perform centralized corporate functions for the Company, pursuant to an agreement with Spectra Energy and its affiliates, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. The Company reimburses Spectra Energy and its affiliates for the expenses to provide these services as well as other expenses they incur on the Company's behalf. Spectra Energy and its affiliates charge such expenses based on the cost of actual services provided or using various allocation methodologies based on the Company's percentage of assets, employees, earnings or other measures, as compared to Spectra Energy's other affiliates.

The Company's transactions with affiliated companies are as follows:

($millions), net	**Transport and Storage Expenses**	**Corporate Charges (Receipts)[a]**	**Gas Purchases**
2015			
St Clair Pipelines 1996, a division of Westcoast	—	(2)	—
Pipeline and Field Services, a division of Westcoast	—	(3)	—
Spectra Energy Empress L.P.	—	—	55
Spectra Energy Gas Transmission LLC	—	14	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—
2014			
Pipeline and Field Services, a division of Westcoast	—	(4)	—
Spectra Energy Empress L.P.	—	—	133
Spectra Energy Gas Transmission LLC	—	10	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—

[a]Excludes compensation arrangements.

Net amounts due (to) from related affiliates are as follows:

($millions), net	**2015**	**2014**
Spectra Energy Empress L.P.	(6)	(10)
Spectra Energy Gas Transmission LLC	(7)	6
Total[a]	(13)	(4)

[a]At December 31, 2015, $14 million (2014 – $10 million) is recognized in Accounts payable and accrued charges and $1 million (2014 – $6 million) is recognized in Accounts receivable, net on the Balance Sheets.

In the normal course of operations, the Company provides or obtains funds from Westcoast on an unsecured basis. The balance outstanding at December 31, 2015 was a payable of $56 million (December 31, 2014 – payable of $48 million). During 2015, interest paid on these loans totalled less than $1 million (2014 – less than $1 million) and interest received on these loans totalled less than $1 million (2014 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

The Company also has a promissory note to borrow up to $150 million from GLBE on an unsecured basis. Funds from this promissory note are used for general corporate purposes. There was no balance outstanding at December 31, 2015 or December 31, 2014.

In addition, beginning in 2014, the Company declared and paid common stock dividends on an annual rather than quarterly basis, and as a result, the Company made a dividend payment to GLBE of $50 million during 2015 (2014 – $100 million).

10. Debt and Credit Facilities

Summary of Debt and Related Terms

($millions)		**December 31, 2015**	December 31, 2014
11.50%	1990 Series debentures, due August 28, 2015	—	150
4.64%	Series 5, due June 30, 2016	**200**	200
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
2.76%	Series 11, due June 2, 2021	**200**	200
4.85%	Series 6, due April 25, 2022	**125**	125
3.79%	Series 10, due July 10, 2023	**250**	250
3.19%	Series 13, due September 17, 2025	**200**	—
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9, due June 21, 2041	**300**	300
4.20%	Series 12, due June 2, 2044	**500**	250
Long-term debt principal (including current maturities)		**3,140**	2,840
Less: Unamortized debt discount		**7**	3
Less: Debt issue costs		**12**	11
Add: Commercial paper		**207**	270
Total debt		**3,328**	3,096
Less: Current maturities of long-term debt		**200**	150
Less: Commercial paper		**207**	270
Total Long-term debt		**2,921**	2,676

The Company's long-term debt is unsecured. Principal repayment requirements on long-term debt are as follows:

($millions)	**Total**	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**
Long-term debt[(a)]	3,140	200	125	400	—	—	2,415

(a) Excludes commercial paper of $207 million.

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2015 and 2014, the Company is in compliance with all such covenants.

Total interest expense on long-term debt in 2015 was $163 million (2014 – $159 million).

Available Credit Facility and Restrictive Debt Covenants

($millions)	Expiration Date	Credit Facility Capacity	Commercial Paper Debt Outstanding at December 31, 2015	December 31, 2014
Multi-year syndicated [a]	2019	500	**207**	270

[a] The credit facility contains a covenant requiring the debt-to-total capitalization ratio, as defined in the agreement, to not exceed 75% and a provision which requires the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 67.8% at December 31 2015 (December 31, 2014 – 68.3%).

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2015 and December 31, 2014 there were no letters of credit issued or revolving borrowings outstanding under the credit facility. The majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2015 was 0.86% (2014 – 1.22%). The weighted average days to maturity on outstanding commercial paper as of December 31, 2015 was 9 days (2014 – 12 days).

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2015 and December 31, 2014, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower.

Total Interest paid on short term debt in 2015 was $1 million (2014 - $1 million).

11. Preferred Stock

	Authorized	Outstanding December 31, 2015	December 31, 2014	December 31, 2015	December 31, 2014
	(shares)	*(shares)*		*($millions)*	
Class A	202,072				
5.5% Series A		**47,672**	47,672	**3**	3
6% Series B		**90,000**	90,000	**5**	5
5% Series C		**49,500**	49,500	**2**	2
4.88% Class B, Series 10	Unlimited	**4,000,000**	4,000,000	**100**	100
				110	110

The Class A, Series A and C Preferred stock are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

The Class A, Series B Preferred stock are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preferred stock are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares once every five years commencing January 1, 2014. The holders of the Class B, Series 10 Preferred stock did not exercise their option on January 1, 2014 and their next optional conversion date is January 1, 2019. Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2018.

The Company has an unlimited number of authorized 4.79% Class B, Series 11 Preferred stock. These shares are cumulative and redeemable at $25 per share at the option of the Company, and at the option of the holders, convertible back into Series 10 shares every five years. At December 31, 2015 and December 31, 2014 none of these shares were issued or outstanding.

The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other type of securities other than preferred stock. As these shares are not solely in the control of the Company, they have been classified as temporary equity on the Balance Sheets.

12. Employee Benefit Plans

Retirement Plans

The Company maintains registered and non-registered, contributory and non-contributory defined benefit (DB Plans) and defined contribution (DC Plan) retirement plans covering substantially all employees. The DB Plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC Plan, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings. The Company also provides non-registered DB Plans to all employees who retire under a registered DB Plan and whose pension is limited by the maximum pension limits under the Income Tax Act.

The Company's policy is to fund the retirement plans, where applicable, on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. Total contributions to the DB Plans were $6 million during the twelve months ended December 31, 2015 and $18 million during the twelve months ended December 31, 2014. Contributions of $6 million in both 2015 and 2014 were made to the Company's DC Plan. The Company anticipates that in 2016 it will make total contributions of approximately $4 million to its DB Plans and $6 million to its DC Plan.

Actuarial gains and losses are amortized over the average remaining service period of active employees. The average remaining service periods of active employees covered by the registered and non-registered DB Plans is 11 years. The Company determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over three years.

Registered and Non-Registered Pension Plans

Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

($millions)	**2015**	2014
Change in Projected Benefit Obligation		
Projected benefit obligation, beginning of year	**863**	748
Service cost	**20**	15
Interest cost	**34**	35
Actuarial (gain) loss	**(5)**	98
Participant contributions	**4**	3
Benefits paid	**(39)**	(36)
Projected benefit obligation, end of year	**877**	863
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**829**	761
Actual return on plan assets	**45**	86
Benefits paid	**(39)**	(36)
Employer contributions	**6**	18
Plan participants' contributions	**4**	3
Expected non-investment expenses	**(3)**	(3)
Plan assets, end of year	**842**	829
Net amount recognized	**(35)**	(34)

Accumulated Benefit Obligation	**824**	812

($millions)	**2015**	2014
Net amount recognized		
Current Liabilities - Other	**(2)**	(2)
Deferred Credits and Other Liabilities - Regulatory and Other	**(61)**	(37)
Other Assets - Other	**28**	5
Total net amount recognized	**(35)**	(34)

The table above includes non-registered pension plans that are not funded and had projected benefit obligations of $42 million at December 31, 2015 and $39 million at December 31, 2014. At December 31, 2015 there were no registered DB plans with accumulated benefit obligations in excess of plan assets. Non-registered DB plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations of $42 million and accumulated benefit obligations of $38 million.

Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)

($millions)	**2015**	2014
Net actuarial loss	**241**	256
Prior service costs	**4**	5
Total amounts recognized in AOCI, pre-tax	**245**	261

Components of Net Periodic Pension Costs

($millions)	**2015**	2014
Net Periodic Pension Cost		
Service cost benefit earned	**22**	18
Interest cost on projected benefit obligation	**34**	35
Expected return on plan assets	**(56)**	(52)
Amortization of prior service cost	**1**	1
Amortization of loss	**22**	18
Net periodic pension cost	**23**	20
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial (gain) loss	**7**	64
Amortization of actuarial loss	**(22)**	(18)
Amortization of prior service cost	**(1)**	(1)
Total recognized in other comprehensive income	**(16)**	45
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	**7**	65

At December 31, 2015, approximately $16 million of actuarial losses will be amortized from AOCI on the Balance Sheets into net periodic pension cost in 2016.

At December 31, 2015, approximately $1 million of prior service costs will be amortized from AOCI on the Balance Sheets into net periodic pension costs in 2016.

Assumptions Used for Pension Benefits Accounting

	2015	2014
Benefit Obligations		
Discount rate	**4.03%**	4.00%
Salary increase	**3.00%**	3.25%
Net Periodic Benefit Cost		
Discount rate	**4.00%**	4.81%
Salary increase	**3.25%**	3.25%
Expected long-term rate of return on plan assets	**7.40%**	7.40%

The discount rates used to determine the benefit obligations are the rates at which the benefit obligations could be effectively settled. The discount rates are developed from yields on available high-quality bonds and reflect each plan's expected cash flows.

The long-term rates of return for the plan assets in 2015 were developed using weighted-average calculations of expected returns based primarily on future expected returns across classes considering the use of active asset managers applied against the plans' respective targeted asset mix.

Registered Pension Plan Assets

Asset Category	Target Allocation	**December 31, 2015**	December 31, 2014
U.S. equity securities	17%	**18%**	17%
Canadian equity securities	25%	**24%**	25%
Other equity securities	13%	**13%**	13%
Fixed income securities	45%	**45%**	45%
Total	100%	**100%**	100%

Pension plan assets are maintained in a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. The Company regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The following table summarizes the fair values of pension plan assets recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in note 14:

($millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
December 31, 2015				
Cash and cash equivalents	3	3	—	—
Fixed income securities	375	375	—	—
Equity securities	464	205	259	—
Total	842	583	259	—
December 31, 2014				
Cash and cash equivalents	2	2	—	—
Fixed income securities	372	372	—	—
Equity securities	455	270	185	—
Total	829	644	185	—

Expected Benefit Payments

($millions)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021-2025**
Expected benefit payments	40	42	44	46	48	257

Other Post-Retirement Benefit Plans

The Company provides health care and life insurance benefits for retired employees on a non-contributory basis predominantly under defined contribution plans. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The other post-retirement benefits are not funded.

Other Post-Retirement Benefit Plans - Change in Projected Benefit Obligation and Fair Value of Plan Assets

($millions)	**2015**	2014
Change in Benefit Obligation		
Accumulated post-retirement benefit obligation, beginning of year	**67**	64
Service cost	**2**	1
Interest cost	**2**	3
Actuarial (gains) losses	**(6)**	1
Benefits paid	**(2)**	(2)
Accumulated post-retirement benefit obligation, end of year	**63**	67
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**—**	—
Benefits paid	**(2)**	(2)
Employer contributions	**2**	2
Plan assets, end of year	**—**	—
Net amount recognized[a]	**(63)**	(67)

[a] $61 million is recognized in Regulatory and other liabilities and $2 million is recognized in Accounts payable and accrued charges on the Balance Sheets.

Other Post-Retirement Benefit Plans - Amounts Recognized in AOCI

($millions)	**December 31, 2015**	December 31, 2014
Net actuarial (gain) loss recognized in AOCI	**(2)**	4

($millions)	**2015**	2014
Other Post-Retirement Benefit Plans - Components of Net Periodic Benefit Cost		
Service cost benefit earned	**2**	1
Interest cost on accumulated post-retirement benefit obligation	**2**	3
Net periodic other post-retirement benefit cost	**4**	4
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial (losses) gains	**(6)**	1
Total recognized in other comprehensive income	**(6)**	1
Total recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**(2)**	5

Other Post-Retirement Benefits Plans - Assumptions Used for Benefits Accounting

	2015	2014
Benefit Obligations		
Discount rate for post-retirement plans	**4.03%**	4.00%
Salary increase	**3.00%**	3.25%
Net Periodic Benefit Cost		
Discount rate for post-retirement plans	**4.00%**	4.83%
Salary increase	**3.25%**	3.25%

The discount rates used to determine the post-retirement obligations are the rates at which the benefit obligations could be effectively settled. The discount rates for the plans are developed from yields on available high-quality bonds in Canada and reflect each plan's expected cash flows.

Assumed Health Care Cost Trend Rates

	2015	2014
Health care cost trend rate assumed for next year	**5.50%**	6.00%
Rate to which the cost trend rate is assumed to decline	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**2017**	2017

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

($millions)	**1% Point Increase**	1% Point Decrease
Effect on total service and interest costs	**1**	—
Effect on post-retirement benefit obligations	**4**	(3)

Other Post-Retirement Benefit Plans - Payments and Receipts

The Company expects to make future benefit payments, which reflect expected future service, as appropriate. The following benefit payments are expected to be paid over each of the next five years and thereafter.

($millions)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021-2025**
Expected benefit payments	2	3	3	3	3	17

Retirement/Savings Plan

The Company has employee savings plans available to eligible employees. Employees may participate in a matching contribution where the Company matches a certain percentage of before tax employee contributions of up to 5% of eligible pay per pay period. The Company expensed pre-tax employer matching contributions of $8 million in both the twelve months ended December 31, 2015 and 2014.

13. Asset Retirement Obligations

The Company's AROs relate to the legal obligation to disconnect, purge and cap abandoned pipelines, capping abandoned storage wells, and in some buildings, special handling and disposition of asbestos if it is disturbed.

The Company has non-asbestos AROs which include easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to the non-asbestos ARO because the fair value of the ARO cannot be reasonably estimated. The Company's pipeline system is considered a critical component of its business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term. The Company has determined that sufficient information to estimate the fair value of an ARO is not available because the assets are considered permanent with indeterminate useful lives and that sufficient information is not available to estimate a range of potential settlement dates in order to employ a present value technique to estimate fair value.

AROs are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

($millions)	**December 31, 2015**	December 31, 2014
Balance, beginning of year	**368**	328
Accretion expense	**17**	16
Liabilities settled	**(7)**	(6)
Revisions in estimated cash flows	**62**	30
Balance, end of year	**440**	368

14. Fair Value Measurements

Financial instruments recorded at fair value on the Balance Sheets are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of the Company's financial instruments that are actively traded in the secondary market are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency. The fair value of the Company's pension plan assets designated as Level 2 financial instruments is determined through the market approach valuation technique using observable inputs including matrix pricing and market corroborated pricing.

Level 3 Valuation Techniques

Level 3 valuation techniques include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation. The fair value of the Company's pension plan assets designated as Level 3 financial instruments is determined through the market approach valuation technique using unobservable inputs including investment manager pricing for private placements and private equities.

There were no transfers between levels during the year ended December 31, 2015.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts that could have been realized in current markets.

	December 31, 2015		December 31, 2014	
($millions)	**Book Value**	**Fair Value**	Book Value	Fair Value
Long-term debt, including current maturities[(a)]	**3,140**	**3,538**	2,840	3,323

[(a)] Excludes unamortized items.

The fair value of the Company's Long-term debt is determined based on market-based prices as described in the Level 2 valuation technique described above.

The fair values of Cash and cash equivalents, Accounts receivable, net, Accounts payable and accrued charges, Short-term borrowings and Commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligations. The maximum exposure to credit risk for the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement cost of gas loans at December 31, 2015 is $51 million receivable (2014 - $102 million receivable). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

The Company manages its credit risk on Cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on Accounts receivable, net the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2015 amounted to $40 million (2014 - $37 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

The Company continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31, 2015**	December 31, 2014
Current	**218**	316
30 Days over due	**10**	13
60 Days over due	**4**	5
90+ Days over due	**11**	12
Total trade accounts receivable	**243**	346
Allowance for doubtful accounts	**(6)**	(6)
Total trade accounts receivable, net[a]	**237**	340

[a] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

For the years ended December 31, 2015 and 2014, no one customer accounted for more than 10% of sales or 10% of receivables.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 10).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2015:

($millions)	**Total**	**2016**	**2017-2018**	**2019-2020**	**Thereafter**
Commercial paper	207	207	—	—	—
Accounts payable and accrued charges	793	793	—	—	—
Long-term debt (including principal and interest)	5,468	359	816	227	4,066
Total	6,468	1,359	816	227	4,066

15. Stock Based Compensation

The Spectra Energy 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 40 million shares of common stock may be awarded under the 2007 LTIP. Union Gas employees participate in the 2007 LTIP.

Stock based performance awards generally vest over three years at the earliest, if performance metrics are met. Spectra Energy granted 36,100 performance awards in 2015 and 38,200 in 2014, with fair values of U.S. $2 million for both 2015 and 2014 to Union Gas employees. There were no performance awards vested in 2015 and the total fair value of the performance awards vested in 2014 was U.S. $1 million. As of December 31, 2015, the Company expects to recognize U.S. $2 million of future compensation cost related to performance awards over a weighted-average period of less than one year.

Stock based phantom awards generally vest over three years. Spectra Energy awarded 22,650 phantom awards in 2015 and 24,200 in 2014, with fair values of U.S. $1 million for both 2015 and 2014 to Union Gas employees. The total fair value of the phantom awards vested was U.S. $1 million in both 2015 and 2014. As of December 31, 2015, the Company expects to recognize U.S. $1 million of future compensation cost related to phantom awards over a weighted-average period of less than two years.

	Performance Awards		**Phantom Awards**	
	Units	**Weighted-Average Grant Date Fair Value U.S. $**	**Units**	**Weighted-Average Grant Date Fair Value U.S. $**
Outstanding, beginning of year	126,519	35	78,872	32
Granted	36,100	48	22,650	37
Vested	—	—	(25,902)	31
Forfeited	(42,516)	21	(523)	19
Outstanding, end of year	120,103	39	75,097	26
Awards expected to vest	116,070	39	74,186	26

16. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Balance Sheets. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company's potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

17. Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated.

In November 2015, the Ontario Ministry of the Environment and Climate Change issued and posted a proposed draft Director's Order (the Order) naming the Company, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of the Company in Hamilton. If issued in its current form, the Order would require all parties to act jointly to develop a Conceptual Site Model to fully delineate the extent of the soil and groundwater contamination and to assess remedial measures, if necessary. In December 2015, the Company requested that the Ministry revise the proposed draft Order to more properly focus only on the party responsible for the contamination, as opposed to those parties impacted by the contamination. The Company is of the view that the cost of any potential remedial measures, if any, cannot be estimated at this time.

Other than the potential contingency noted above, of which the impact is unknown, the Company has no reason to believe that the ultimate outcome of these matters could have a significant impact on its Financial Statements.

18. Subsequent Events

Management has evaluated significant events and transactions that occurred from January 1, 2016 through March 3, 2016, the date the financial statements were filed, and no subsequent events requiring disclosure were noted.

DIRECTORS

David G. Unruh
Stephen W. Baker
Bruce E. Pydee

OFFICERS

Stephen W. Baker
Chair and President

J. Patrick Reddy
Chief Financial Officer

M. Richard Birmingham
Vice President, Regulatory, Lands and Public Affairs

Bruce E. Pydee
Vice President and General Counsel

Janice L. Ferguson
Vice President, Human Resources

Mark J. Isherwood
Vice President, Business Development - Storage and Transmission

Paul Rietdyk
Vice President, Engineering, Construction and Storage and Transmission Operations

Michael G.P. Shannon
Vice President, Distribution Operations

Wendy H. Zelond
Vice President, Finance

Laura J. Sayavedra
Vice President and Treasurer

Timothy J. Kennedy
Vice President, Government and Aboriginal Affairs

David G. Simpson
Vice President, In-Franchise Sales, Marketing and Customer Care

Paul K. Haralson
Assistant Treasurer

Annachiara Jones
Corporate Secretary

Patricia M. Rice
Assistant Corporate Secretary

Tanya Mushynski
Assistant Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **CST Trust Company**

Union Gas Limited preferred stock are listed on the Toronto Stock Exchange
Class A Preferred, Series A - 5½% (UNG.PR.C)

Class A Preferred, Series B - 6% (UNG.PR.D)

REGISTERED OFFICE

50 Keil Drive North
Chatham, Ontario N7M 5M1

The Financial Statements and all information in this report have been prepared by and are the responsibility of management. The Financial Statements have been prepared in conformity with generally accepted accounting principles in the United States of America and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon Union Gas Limited's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors (the Board) is responsible for ensuring that management fulfils its responsibility for financial reporting and for final approval of the Financial Statements.

The Board meets regularly with management, the internal auditors and the shareholders' auditors to review the Financial Statements, the Independent Auditor's Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Board, as does the Director of Internal Audit Services.

Deloitte LLP performed an independent audit of the 2016 and 2015 Financial Statements in this report. Their independent professional opinion on the fairness of these Financial Statements is included in the Independent Auditor's Report.

February 26, 2017

Stephen W. Baker	J. Patrick Reddy
President	Chief Financial Officer

Deloitte.

Deloitte LLP
150 Ouellette Place
Suite 200
Windsor ON N8X 1L9
Canada

Tel: 519-967-0388
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Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying financial statements of Union Gas Limited, which comprise the balance sheets as at December 31, 2016 and December 31, 2015, and the statements of operations and comprehensive income, statements of equity, and statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2016 and December 31, 2015, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Deloitte LLP

Chartered Professional Accountants
Licensed Public Accountants
February 26, 2017

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the Years Ended December 31 ($millions)	**2016**	2015
Gas sales and distribution revenue	**1,529**	1,675
Cost of gas (note 9)	**717**	875
Gas distribution margin	**812**	800
Storage and transportation revenue (note 9)	**278**	239
Other revenue, net	**21**	26
Net operating revenue	**1,111**	1,065
Expenses		
Operating and maintenance (note 9)	**414**	399
Depreciation and amortization	**239**	224
Property taxes and other	**71**	69
Total expenses	**724**	692
Income before interest and income taxes	**387**	373
Interest expense (notes 9 and 10)	**161**	157
Income before income taxes	**226**	216
Income tax expense (note 6)	**21**	28
Net income	**205**	188
Preferred shares dividends	**3**	3
Net income applicable to common stock	**202**	185
Other comprehensive (loss) income, net of tax		
Pension and benefits impact (net of tax of (3) and 6 respectively) (note 12)	**(7)**	16
Comprehensive income applicable to common stock	**195**	201

(See accompanying notes)

BALANCE SHEETS

As at December 31 ($millions)	**2016**	2015
Assets		
Current assets		
Cash and cash equivalents	**27**	5
Accounts receivable, net (notes 3, 4 and 9)	**816**	648
Income taxes receivable (note 6)	**29**	24
Inventories (note 5)	**245**	299
Total current assets	**1,117**	976
Property, plant and equipment (note 7)		
Cost	**9,270**	8,300
Accumulated depreciation and amortization	**2,762**	2,622
Property, plant and equipment, net	**6,508**	5,678
Regulatory and other assets (notes 2, 3 and 8)	**602**	536
Total Assets	**8,227**	7,190
Liabilities and Equity		
Current liabilities		
Short-term borrowings (note 9)	**253**	56
Commercial paper (note 10)	**333**	207
Accounts payable and accrued charges (notes 4 and 9)	**878**	793
Current maturities of long-term debt (note 10)	**125**	200
Total current liabilities	**1,589**	1,256
Long-term liabilities		
Long-term debt (note 10)	**3,295**	2,921
Deferred income taxes (note 6)	**516**	451
Asset retirement obligations (note 13)	**417**	440
Regulatory and other liabilities (notes 2 and 8)	**602**	509
Total long-term liabilities	**4,830**	4,321
Total Liabilities	**6,419**	5,577
Preferred Shares (note 11)	**110**	110
Equity		
Common stock, unlimited shares authorized, 57,822,650 outstanding	**627**	627
Retained earnings	**1,253**	1,051
Accumulated other comprehensive loss	**(186)**	(179)
Paid-in capital	**4**	4
Total Equity	**1,698**	1,503
Total Liabilities and Equity	**8,227**	7,190

(See accompanying notes)

Approved by the Board

Director
David Unruh

Director
Steve Baker

STATEMENTS OF CASH FLOWS

For the Years Ended December 31 ($millions)	**2016**	2015
Operating Activities		
Net income	**205**	188
Items not affecting cash		
Depreciation and amortization	**239**	224
Loss on disposal of assets	**1**	—
Deferred income taxes	**8**	(40)
Changes in working capital		
Accounts receivable	**(126)**	89
Inventories	**40**	(60)
Accounts payable, accrued charges and other	**35**	100
Net cash provided by operating activities	**402**	501
Investing Activities		
Capital expenditures	**(1,036)**	(701)
Net increase in restricted funds	**37**	—
Net cash used in investing activities	**(999)**	(701)
Financing Activities		
Net increase in short-term borrowings	**197**	8
Net increase (decrease) in commercial paper	**126**	(63)
Long-term debt issued	**499**	445
Long-term debt repayments	**(200)**	(150)
Purchase of subsidiary shares from non-controlling interest	**—**	(2)
Dividends paid	**(3)**	(53)
Net cash provided by financing activities	**619**	185
Change in cash and cash equivalents, during the year	**22**	(15)
Cash and cash equivalents, beginning of year	**5**	20
Cash and cash equivalents, end of year	**27**	5
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest, net of amounts capitalized	**158**	160
Cash payments of income taxes, net of refunds received	**9**	66
Property, plant and equipment noncash accruals	**24**	17

(See accompanying notes)

STATEMENTS OF EQUITY

($millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Paid-in Capital	Non-controlling Interest	Total
December 31, 2015	627	1,051	(179)	4	—	1,503
Net income	—	205	—	—	—	205
Other comprehensive loss	—	—	(7)	—	—	(7)
Dividends						
Preferred shares	—	(3)	—	—	—	(3)
December 31, 2016	627	1,253	(186)	4	—	1,698
December 31, 2014	627	916	(195)	—	8	1,356
Net income	—	188	—	—	—	188
Other comprehensive income	—	—	16	—	—	16
Dividends						
Preferred shares	—	(3)	—	—	—	(3)
Common stock	—	(50)	—	—	—	(50)
Purchase of subsidiary shares from non-controlling interest	—	—	—	4	(8)	(4)
December 31, 2015	627	1,051	(179)	4	—	1,503

(See accompanying notes)

UNION GAS LIMITED
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2016 AND 2015

1. Summary of Operations and Significant Accounting Policies

The terms "Union Gas" or "the Company" as used in these Financial Statements refer to Union Gas Limited unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. Union Gas' common stock is held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

On September 6, 2016, Spectra Energy announced that it entered into a definitive merger agreement with Enbridge Inc. (Enbridge). Under this agreement, Enbridge and Spectra Energy will combine in a stock-for-stock merger transaction, which values Spectra Energy's stock at approximately $37 billion, based on the closing price of Enbridge common shares as of September 2, 2016. This transaction was approved by the boards of directors and shareholders of both Spectra Energy and Enbridge and has received all necessary regulatory approvals. The transaction is expected to close on February 27, 2017.

Upon completion of the proposed merger, Spectra Energy shareholders will receive 0.984 Enbridge common shares for each share of Spectra Energy stock they own. The consideration to be received is valued at U.S. $40.33 per Spectra Energy share, based on the closing price of Enbridge common shares as of September 2, 2016, representing an approximate 11.5% premium to the closing price of Spectra Energy stock as of September 2, 2016. Upon completion of the merger, Enbridge shareholders are expected to own approximately 57% of the combined company and Spectra Energy shareholders are expected to own approximately 43%.

As a result of this transaction, Enbridge and its subsidiaries will own Union Gas through their ownership of Spectra Energy.

Nature of Operations

Union Gas owns and operates natural gas distribution, storage and transmission facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy market participants. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the distribution, storage and transportation of natural gas.

Basis of Presentation

The Financial Statements of the Company include the standalone accounts of the Company and have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). All amounts are presented in millions of Canadian dollars except where noted.

In 2014, Canadian securities regulators approved the extension of the Company's exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

Use of Estimates

The preparation of the Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual amounts could differ from these estimates.

Regulation

The Company is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act, (1998)*. This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within the Company and provides the framework required to support new storage investments.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and its ability to achieve forecasted revenues and manage costs.

Effective January 1, 2014, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts.

As part of the Company's OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings in excess of 100 basis points above the benchmark return on equity are shared with ratepayers as a reduction in earnings during the year, if applicable.

The Company follows U.S. GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered and collection is reasonably assured. Revenues related to these services provided or products delivered but not yet billed are estimated each month.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred on the Balance Sheets for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the cost of gas an estimated amount of these differences based upon the methodology used by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Income Taxes

Deferred income taxes are recognized for differences between the financial reporting and tax bases of assets and liabilities at enacted statutory tax rates in effect for the years in which the differences are expected to reverse. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Actual income taxes could vary from these estimates due to the future changes in income tax law or results from the final review of tax returns by federal and provincial tax authorities.

Financial statement effects on tax positions are recognized in the period in which it is more likely than not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest related to the unrecognized tax benefits is recorded as Interest expense on the Statements of Operations and Comprehensive Income.

Inventories

Gas in storage for resale to customers is carried at weighted average cost approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred on the Balance Sheets for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment is stated at historical cost less accumulated depreciation and amortization. The Company capitalizes all construction-related direct labour and material costs, as well as indirect construction costs. Indirect costs include general engineering and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred.

Regulated depreciation is computed based on the asset's average service life using the straight-line method. Unregulated depreciation is computed based on management's assumption of useful life using the straight-line method.

When regulated property, plant and equipment is retired, the original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation and amortization. When entire regulated operating units are sold or non-regulated property, plant and equipment is retired, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Asset Retirement Obligations (AROs)

The Company recognizes AROs for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within the Company's control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

Stock-Based Compensation

Union Gas employees participate in a stock-based compensation plan sponsored by Spectra Energy. For employee awards, equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests, the date the employee becomes retirement-eligible, or the date the award market condition is met. Awards, including stock options, granted to employees that are already retirement-eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

Pension and Other Post-Retirement Benefits

The Company fully recognizes the overfunded or underfunded status of pension and other post-retirement benefit plans as Regulatory and other assets, Accounts payable and accrued charges, or Regulatory and other liabilities on the Balance Sheets. A plan's funded status is the difference between the fair value of plan assets and the plan's benefit obligation. The Company records deferred plan costs and income (unrecognized losses and gains, and unrecognized prior service costs and credits) in Accumulated other comprehensive loss, until they are amortized to be recognized as a component of benefit expense within Operating and maintenance expenses in the Statements of Operations and Comprehensive Income. See note 12 for further discussion.

New Accounting Pronouncements

In May 2014, the FASB issued ASU 2014-09,*"Revenue from Contracts with Customers (Topic 606),"* in an effort to improve revenue recognition practices across entities and industries. The ASU introduces a single, principles-based revenue recognition model which centers on the core principle of an entity recognizing revenue in a manner that depicts the transfer of goods and services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. Since its release, the FASB has issued multiple amendments clarifying and/or amending ASU 2014-09. The Company has substantially completed a review of contracts with customers in relation to the requirements of ASU 2014-09. While the Company has not identified any material difference in the amount or timing of revenue recognition for the categories the Company has reviewed to date, the evaluation is not complete and the Company has not concluded on the overall impacts of adopting this standard. In addition, the Company is in the process of implementing appropriate changes to business processes, systems and controls to support the recognition and disclosure requirements under the new standard. ASU 2014-09 is effective for the Company on January 1, 2018 and allows for either full retrospective or modified retrospective adoption.

In January 2016, the FASB issued ASU 2016-01, "*Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financials Assets and Financial Liabilities,*" which amends the classification and measurement of financial instruments. Changes primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. This ASU is effective for the Company beginning after December 15, 2017. Early adoption is not permitted. The Company is currently evaluating this ASU and its potential impact.

In February 2016, the FASB issued Accounting Standards Update (ASU) No. 2016-02, "*Leases (Topic 842),*" to improve the financial reporting around leasing transactions. The new guidance requires companies to begin recording assets and liabilities arising from those leases classified as operating leases under previous guidance. Furthermore, the new guidance will require significant additional disclosures about the amount, timing and uncertainty of cash flows from leases. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in previous guidance. The result of retaining a distinction between finance leases and operating leases is that under the lessee accounting model in Topic 842, the effect of leases in the statement of comprehensive income and the statement of cash flows is largely unchanged from previous guidance. This ASU is effective for the Company January 1, 2019. The Company is currently evaluating this ASU and its potential impact.

In March 2016, the FASB issued ASU No. 2016-09, "*Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting,*" which simplifies several aspects of the accounting for share-based payment award transactions. The update requires classification changes for certain tax cash flows within the statement of cash flows and requires all excess tax benefits and tax deficiencies to be recorded through the Statement of Operations. In addition, the update provides an accounting policy election around forfeitures and raises the threshold for liability classification of share-based awards withheld for tax withholding requirements. This ASU is effective for the Company January 1, 2017. This ASU is not expected to have a material impact on the Company's Financial Statements.

In June 2016, the FASB issued ASU No. 2016-13, "*Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments,*" to replace the incurred loss impairment methodology with a methodology that reflects expected credit losses and requires the consideration of a broader range of reasonable and supportable information to inform credit loss estimates. This ASU is effective for the Company January 1, 2020. The Company is currently evaluating this ASU and its potential impact.

In August 2016, the FASB issued ASU No. 2016-15, "*Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments,*" to provide guidance on specific cash flow issues with the objective of reducing the existing diversity in practice. This ASU is effective for the Company January 1, 2018. The Company is currently evaluating this ASU and its potential impact.

In November 2016, the FASB issued ASU No. 2016-18, *"Statement of Cash Flows (Topic 230): Restricted Cash,"* to address the diversity in the classification and presentation of changes in restricted cash and restricted cash equivalents on the statement of cash flows. The update requires that restricted cash and restricted cash equivalents be included with Cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the Statement of Cash Flows. This ASU is effective for the Company on January 1, 2018. The Company is currently evaluating this ASU and its potential impact.

2. Regulatory Matters

Regulatory Assets and Liabilities

The Company recorded the following assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	**December 31, 2016**	December 31, 2015	Recovery/Settlement Period
Regulatory assets[a]				
Customer deferrals	Accounts receivable, net	**82**	43	Less than 1 year
Gas in storage inventory	Inventories	**13**	53	Less than 1 year
Deferred income taxes – long-term[b]	Regulatory and other assets	**462**	403	2 years – exceeds remaining life of asset
Total regulatory assets		**557**	499	
Regulatory liabilities[a]				
Other deferrals – current[b]	Accounts payable and accrued charges	**7**	7	Less than 1 year
Customer deferrals	Accounts payable and accrued charges	**16**	1	Less than 1 year
Gas cost deferrals	Accounts payable and accrued charges	**13**	67	Less than 1 year
Asset removal costs[b]	Regulatory and other liabilities	**394**	357	Exceeds remaining life of asset
Total regulatory liabilities		**430**	432	

[a] All regulatory assets and liabilities are excluded from rate base unless otherwise noted.

[b] All or a portion of the balance is included in rate base.

The Company has regulatory assets of $462 million as of December 31, 2016 and $403 million as of December 31, 2015 related to deferred income tax liabilities. Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since substantially all of these timing differences are related to property, plant and equipment costs, recovery of these regulatory assets is expected to occur over the life of those assets.

The Company has regulatory liabilities associated with plant removal costs of $394 million as of December 31, 2016 and $357 million as of December 31, 2015. These regulatory liabilities represent collections from customers under approved rates for future asset removal activities that are expected to occur associated with its regulated facilities.

In addition, the Company has regulatory liabilities of $13 million as of December 31, 2016 and $67 million as of December 31, 2015 representing gas cost collections from customers under approved rates that vary from the actual cost of gas for the associated periods. The Company files an application quarterly with the OEB to ensure that customers' rates are updated to reflect published forward-market prices. The difference between the approved and actual cost of gas is deferred for future repayment to or refund from customers.

Rate Related Information

The Company's distribution rates, beginning January 1, 2014 are set under a five-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation,
- rate increases or decreases in the small volume customer classes where average use declines or increases,
- certain adjustments to base rates,
- the continued pass-through of gas commodity, upstream transportation and demand side management costs,
- the additional pass-through of costs associated with major capital investments and certain fuel variances,
- an allowance for unexpected cost changes that are outside of management's control,
- equal sharing of tax changes between the Company and its customers, and
- an earnings sharing mechanism that permits the Company to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.

Annual Deferral Account Disposition

In April 2016, the Company filed an application with the OEB for the annual disposition of the 2015 deferral account balances. The impact was a net receivable from customers of approximately $23 million. In August 2016, a decision from the OEB was received approving recovery from ratepayers which began October 1, 2016.

Demand Side Management (DSM)

In June 2016, a decision from the OEB was received approving recovery of the 2014 DSM deferral and variance account balances from ratepayers. The Company began recovery of approximately $11 million from customers on October 1, 2016.

In March 2016, the Company filed a Draft Rate Order with the OEB for rates effective January 1, 2016 based on the OEB's February 24, 2016 updated Decision and Order on the 2015-2020 DSM Plan. In May 2016, a decision from the OEB was received approving recovery in rates of the incremental 2016 DSM related charges from ratepayers of approximately $24 million effective January 1, 2016. The impact on a typical residential customer ranged from an increase of $7 to $9 annually, depending on the customer's location within the Company's service territory. These charges are being recovered over a six month period which began July 1, 2016 for general service rate classes and as a one-time adjustment for contract rate classes that was made in July 2016.

As part of the Company's 2017 rates application, the Company has included an approved DSM budget of approximately $58 million in 2017 rates. The 2017 budget was approved as part of the OEB Revised Decision in the 2015-2020 DSM Plan proceeding.

3. Restricted Cash

The Company had $37 million of restricted funds at December 31, 2016, with $15 million classified as Accounts receivable net, and $22 million classified as Regulatory and other assets. These restricted funds are related to money received from the Province of Ontario (the Province) under the Green Investment Fund program. The funds from this program are to be used by May 31, 2019 to help eligible homeowners reduce their energy consumption and greenhouse gas emissions. The Company is acting as an intermediary for the transfer of funds between the Province and approximately 12,000 eligible homeowners.

Changes in restricted balances are presented within Investing Activities on the Company's Statements of Cash Flows.

4. Gas Imbalances

The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Balance Sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

At December 31, 2016 Accounts receivable, net and Accounts payable and accrued charges include $410 million (2015 – $350 million) related to gas imbalances and gas balancing services.

5. Inventories

Gas in storage includes gas for delivery to customers and for use in the Company's operations. Inventories of materials and supplies are for use in the Company's operations.

($millions)	**December 31, 2016**	December 31, 2015
Gas in storage	**222**	279
Materials and supplies	**23**	20
	245	299

6. Income Taxes

Income Tax Expense Components

($millions)	**2016**	2015
Current		
Federal	**12**	43
Provincial	**1**	25
Total current tax expense	**13**	68
Deferred		
Federal	**5**	(24)
Provincial	**3**	(16)
Total deferred tax expense	**8**	(40)
Total Income taxes	**21**	28

Reconciliation of Income Tax Expense at the Combined Federal and Ontario Statutory Tax Rate to Actual Income Tax Expense

($millions)	**2016**	2015
Income before income taxes	**226**	216
Statutory income tax rate	**26.5%**	26.5%
Statutory income tax rate applied to accounting income	**60**	57
Increase/(decrease) resulting from:		
Deferred income tax adjustments related to rate regulated operations	**(44)**	(33)
Other - net	**5**	4
Total income tax expense	**21**	28
Effective rate of income tax	**9.3%**	13.0%

Net Deferred Income Tax Liability Components

($millions)	**December 31, 2016**	December 31, 2015
Deferred income tax liabilities		
Accelerated depreciation rates	**405**	370
Regulatory asset	**121**	105
Reserves	**20**	(1)
Other	**(30)**	(23)
Total deferred income tax liabilities	**516**	451

Reconciliation of Gross Unrecognized Income Tax Benefits

($millions)	**December 31, 2016**	December 31, 2015
Balance, beginning of year	**28**	19
Increases related to prior year tax positions	**8**	11
Increases related to current year tax positions	**3**	2
Reductions due to lapse of statute of limitations	**(1)**	(4)
Balance, end of year	**38**	28

Unrecognized tax benefits totalled $38 million at December 31, 2016. Of this, $37 million would reduce the effective tax rate if recognized on or after January 1, 2017. The Company recorded a net increase of $10 million in gross unrecognized tax benefits in 2016. This was a result of $1 million attributable to deferred tax liability and $11 million increase in income tax expense.

The Company recognized potential accrued interest related to unrecognized tax benefits as interest expense. Nil was recorded to interest expense in 2016 compared to a $1 million benefit in 2015. Accrued interest totalled $1 million at December 31, 2016 and $1 million at December 31, 2015.

Although uncertain, the Company believes it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $11 million prior to December 31, 2017. The anticipated changes in unrecognized tax benefits relate to the expiration of statutes of limitations and expected audit settlements.

The Company remains subject to examination for income tax returns for years 2009 through 2015.

7. Property, Plant and Equipment, net

($millions)	Useful Life	**December 31, 2016**	December 31, 2015
	(years)		
Plant			
Natural gas transmission	32 - 58	**2,734**	2,210
Natural gas distribution	25 - 60	**4,697**	4,494
Storage	10 - 50	**924**	887
Land rights and rights of way	48 - 61	**137**	120
Other buildings and improvements	2 - 42	**62**	62
Equipment	4 - 15	**82**	86
Vehicles	6	**57**	56
Land	—	**90**	78
Construction in progress	—	**382**	193
Software	4 - 10	**84**	89
Other	15 - 18	**21**	25
Total Property, plant and equipment		**9,270**	8,300
Total accumulated depreciation		**2,672**	2,545
Total accumulated amortization		**90**	77
Total Property, plant and equipment, net		**6,508**	5,678

The Company had no capital leases at December 31, 2016 or 2015.

95% of the Company's property, plant and equipment is regulated with estimated useful lives based on rates approved by the OEB. Composite weighted-average depreciation rates were 2.90% for 2016 and 2.97% for 2015.

The Company capitalized interest of $12 million in 2016 and $7 million in 2015.

Amortization expense of intangible assets totaled $17 million in 2016 and $18 million in 2015. Estimated amortization expense for the next five years is as follows:

($millions)	**2017**	**2018**	**2019**	**2020**	**2021**
Estimated amortization expense	15	12	10	8	7

8. Regulatory and Other Assets and Liabilities

($millions)	**December 31, 2016**	December 31, 2015
Regulatory assets	**462**	403
Restricted cash	**22**	—
Goodwill	**12**	12
Pension assets	**27**	28
Gas balancing	**67**	67
Material and supplies	**10**	10
Deposits on projects	**—**	14
Other	**2**	2
Total Regulatory and other assets	**602**	536
Regulatory liabilities	**394**	357
Pension liabilities	**147**	122
Unrecognized tax benefits	**38**	28
Accrued liabilities[(a)]	**22**	—
Other	**1**	2
Total Regulatory and other liabilities	**602**	509

[(a)]Includes $22 million (2015 - $nil) related to the Green Investment Fund program. See Note 3.

9. Related Party Transactions

The Company occasionally performs services for and incurs costs on behalf of the Company's affiliates, which are subsequently reimbursed. Likewise, certain affiliates may perform services for or incur costs on behalf of the Company, which are then reimbursed by the Company. These transactions are in the normal course of operations and are recorded at exchange amounts agreed to between the related parties.

In addition, Spectra Energy and its affiliates perform centralized corporate functions for the Company, pursuant to an agreement with Spectra Energy and its affiliates, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. The Company reimburses Spectra Energy and its affiliates for the expenses to provide these services as well as other expenses they incur on the Company's behalf. Spectra Energy and its affiliates charge such expenses based on the cost of actual services provided or using various allocation methodologies based on the Company's percentage of assets, employees, earnings or other measures, as compared to Spectra Energy's other affiliates.

The Company's transactions with affiliated companies are as follows:

($millions), net	**Transport and Storage Expenses**	**Corporate Charges (Receipts)[(a)]**	**Gas Purchases**
2016			
St Clair Pipelines 1996, a division of Westcoast	—	(2)	—
Pipeline and Field Services, a division of Westcoast	—	(4)	—
Spectra Energy Empress L.P.	—	—	21
Spectra Energy Gas Transmission LLC	—	21	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—
2015			
St Clair Pipelines 1996, a division of Westcoast	—	(2)	—
Pipeline and Field Services, a division of Westcoast	—	(3)	—
Spectra Energy Empress L.P.	—	—	55
Spectra Energy Gas Transmission LLC	—	14	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—

(a)Excludes compensation arrangements.

Net amounts due (to) from related affiliates are as follows:

($millions), net	**2016**	2015
Spectra Energy Empress L.P.	**—**	(6)
Spectra Energy Gas Transmission LLC	**(1)**	(7)
Total[(a)]	**(1)**	(13)

(a)At December 31, 2016, $5 million (2015 – $14 million) is recognized in Accounts payable and accrued charges and $4 million (2015 – $1 million) is recognized in Accounts receivable, net on the Balance Sheets.

In the normal course of operations, the Company provides or obtains funds from Westcoast on an unsecured basis. The balance outstanding at December 31, 2016 was a payable of $253 million (December 31, 2015 – payable of $56 million). During 2016, interest paid on these loans totalled less than $1 million (2015 – less than $1 million) and interest received on these loans totalled less than $1 million (2015 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

The Company also has a promissory note to borrow up to $150 million from GLBE on an unsecured basis. Funds from this promissory note are used for general corporate purposes. There was no balance outstanding at December 31, 2016 or December 31, 2015.

In 2016, no common stock dividend payments were made to GLBE (2015 – $50 million).

10. Debt and Credit Facilities

Summary of Debt and Related Terms

($millions)		**December 31, 2016**	December 31, 2015
4.64%	Series 5, due June 30, 2016	—	200
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
2.76%	Series 11, due June 2, 2021	**200**	200
4.85%	Series 6, due April 25, 2022	**125**	125
3.79%	Series 10, due July 10, 2023	**250**	250
3.19%	Series 13, due September 17, 2025	**200**	200
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
2.81%	Series 14, due June 1, 2026	**250**	—
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9, due June 21, 2041	**300**	300
4.20%	Series 12, due June 2, 2044	**500**	500
3.80%	Series 15, due June 1, 2046	**250**	—
Long-term debt principal (including current maturities)		**3,440**	3,140
Less: Unamortized debt discount		**7**	7
Less: Debt issue costs		**13**	12
Add: Commercial paper		**333**	207
Total debt		**3,753**	3,328
Less: Current maturities of long-term debt		**125**	200
Less: Commercial paper		**333**	207
Total Long-term debt		**3,295**	2,921

The Company's long-term debt is unsecured. Principal repayment requirements on long-term debt are as follows:

($millions)	**Total**	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**
Long-term debt[(a)]	3,440	125	400	—	—	200	2,715

(a) Excludes commercial paper of $333 million.

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2016 and 2015, the Company is in compliance with all such covenants.

Total interest expense on long-term debt in 2016 was $169 million (2015 – $163 million).

Available Credit Facility and Restrictive Debt Covenants

			Commercial Paper Debt Outstanding at	
($millions)	**Expiration Date**	**Credit Facility Capacity**	**December 31, 2016**	December 31, 2015
Multi-year syndicated [(a), (b)]	2021	700	**333**	207

[(a)] The credit facility contains a covenant requiring the debt-to-total capitalization ratio, as defined in the agreement, to not exceed 75% and a provision which requires the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 69.0% at December 31 2016 (December 31, 2015 – 67.8%).

[(b)] In April 2016, the Company amended the revolving credit agreement. The facility was increased from $500 million to $700 million and its expiration date was extended from 2019 to 2021.

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2016 and December 31, 2015 there were no letters of credit issued or revolving borrowings outstanding under the credit facility. The majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2016 was 0.87% (2015 – 0.86%). The weighted average days to maturity on outstanding commercial paper as of December 31, 2016 was 8 days (2015 – 9 days).

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2016 and December 31, 2015, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower.

Total Interest paid on short term debt in 2016 was $1 million (2015 – $1 million).

11. Preferred Shares

		Outstanding			
	Authorized	**December 31, 2016**	December 31, 2015	**December 31, 2016**	December 31, 2015
	(shares)	*(shares)*		*($millions)*	
Class A	202,072				
5.5% Series A		**47,672**	47,672	**3**	3
6% Series B		**90,000**	90,000	**5**	5
5% Series C		**49,500**	49,500	**2**	2
4.88% Class B, Series 10	Unlimited	**4,000,000**	4,000,000	**100**	100
				110	110

The Class A, Series A and C Preferred shares are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

The Class A, Series B Preferred shares are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preferred shares are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares once every five years commencing January 1, 2014. The holders of the Class B, Series 10 Preferred shares did not exercise their option on January 1, 2014 and their next optional conversion date is January 1, 2019. The Company may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2018.

The Company has an unlimited number of authorized 4.79% Class B, Series 11 Preferred shares. These shares are cumulative and redeemable at $25 per share at the option of the Company, and at the option of the holders, convertible back into Series 10 shares, commencing on January 15, 2026 and on each fifth anniversary thereafter (each such anniversary, a Series 11 Conversion Date). Additionally, these shares are redeemable at $25.50 per share at the option of the Company on any date after January 15, 2026 that is not a Series 11 Conversion Date. At December 31, 2016 and December 31, 2015 none of these shares were issued or outstanding.

The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other type of securities other than preferred shares. As these shares are not solely in the control of the Company, they have been classified as temporary equity on the Balance Sheets.

12. Employee Benefit Plans

Retirement Plans

The Company maintains registered and non-registered, contributory and non-contributory defined benefit (DB Plans) and defined contribution (DC Plan) retirement plans covering substantially all employees. The DB Plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC Plan, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings. The Company also provides non-registered DB Plans to all employees who retire under a registered DB Plan and whose pension is limited by the maximum pension limits under the Income Tax Act.

The Company's policy is to fund the retirement plans, where applicable, on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. Total contributions to the DB Plans were $4 million during the twelve months ended December 31, 2016 and $6 million during the twelve months ended December 31, 2015. Contributions of $6 million in both 2016 and 2015 were made to the Company's DC Plan. The Company anticipates that in 2017 it will make total contributions of approximately $15 million to its DB Plans and $6 million to its DC Plan.

Actuarial gains and losses are amortized over the average remaining service period of active employees. The average remaining service periods of active employees covered by the registered and non-registered DB Plans is 13 years. The Company determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over three years.

Registered and Non-Registered Pension Plans

Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

($millions)	**2016**	2015
Change in Projected Benefit Obligation		
Projected benefit obligation, beginning of year	**877**	863
Service cost	**19**	20
Interest cost	**35**	34
Actuarial (gain) loss	**22**	(5)
Participant contributions	**4**	4
Benefits paid	**(40)**	(39)
Projected benefit obligation, end of year	**917**	877
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**842**	829
Actual return on plan assets	**47**	45
Benefits paid	**(40)**	(39)
Employer contributions	**4**	6
Plan participants' contributions	**4**	4
Expected non-investment expenses	**(3)**	(3)
Plan assets, end of year	**854**	842
Net amount recognized	**(63)**	(35)

Accumulated Benefit Obligation	**866**	824

($millions)	**2016**	2015
Net amount recognized		
Current Liabilities - Other	**(2)**	(2)
Deferred Credits and Other Liabilities - Regulatory and Other	**(88)**	(61)
Other Assets - Other	**27**	28
Total net amount recognized	**(63)**	(35)

The table above includes non-registered pension plans that are not funded and had projected benefit obligations of $47 million at December 31, 2016 and $42 million at December 31, 2015. At December 31, 2016 plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations of $519 million, accumulated benefit obligations of $475 million and fair value of plan assets of $428 million.

Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)

($millions)	**2016**	2015
Net actuarial loss	**257**	241
Prior service costs	**2**	4
Total amounts recognized in AOCI, pre-tax	**259**	245

Components of Net Periodic Pension Costs

($millions)	**2016**	2015
Net Periodic Pension Cost		
Service cost benefit earned	**22**	22
Interest cost on projected benefit obligation	**35**	34
Expected return on plan assets	**(57)**	(56)
Amortization of prior service cost	**1**	1
Amortization of loss	**17**	22
Net periodic pension cost	**18**	23
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial (gain) loss	**32**	7
Amortization of actuarial loss	**(17)**	(22)
Amortization of prior service cost	**(1)**	(1)
Total recognized in other comprehensive income	**14**	(16)
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	**32**	7

At December 31, 2016, approximately $14 million of actuarial losses will be amortized from AOCI on the Balance Sheets into net periodic pension cost in 2017.

At December 31, 2016, approximately $1 million of prior service costs will be amortized from AOCI on the Balance Sheets into net periodic pension costs in 2017.

Assumptions Used for Pension Benefits Accounting

	2016	2015
Benefit Obligations		
Discount rate	**3.81%**	4.03%
Salary increase	**3.00%**	3.00%
Net Periodic Benefit Cost		
Discount rate	**4.03%**	4.00%
Salary increase	**3.00%**	3.25%
Expected long-term rate of return on plan assets	**7.15%**	7.40%

The discount rates used to determine the benefit obligations are the rates at which the benefit obligations could be effectively settled. The discount rates are developed from yields on available high-quality bonds and reflect each plan's expected cash flows.

The long-term rates of return for the plan assets in 2016 were developed using weighted-average calculations of expected returns based primarily on future expected returns across classes considering the use of active asset managers applied against the plans' respective targeted asset mix.

Registered Pension Plan Assets

Asset Category	Target Allocation	**December 31, 2016**	December 31, 2015
U.S. equity securities	15%	**16%**	18%
Canadian equity securities	23%	**28%**	24%
Other equity securities	15%	**15%**	13%
Fixed income securities	39%	**41%**	45%
Other investments	8%	**—%**	—%
Total	100%	**100%**	100%

Pension plan assets are maintained in a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. The Company regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The following table summarizes the fair values of pension plan assets recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in note 14:

($millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
December 31, 2016				
Cash and cash equivalents	3	3	—	—
Fixed income securities	350	350	—	—
Equity securities	501	242	259	—
Total	854	595	259	—
December 31, 2015				
Cash and cash equivalents	3	3	—	—
Fixed income securities	375	375	—	—
Equity securities	464	205	259	—
Total	842	583	259	—

Expected Benefit Payments

($millions)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022-2026**
Expected benefit payments	43	44	46	48	49	260

Other Post-Retirement Benefit Plans

The Company provides health care and life insurance benefits for retired employees on a non-contributory basis predominantly under defined contribution plans. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The other post-retirement benefits are not funded.

Other Post-Retirement Benefit Plans - Change in Projected Benefit Obligation and Fair Value of Plan Assets

($millions)	**2016**	2015
Change in Benefit Obligation		
Accumulated post-retirement benefit obligation, beginning of year	**63**	67
Service cost	**1**	2
Interest cost	**3**	2
Actuarial (gains) losses	**(4)**	(6)
Benefits paid	**(2)**	(2)
Accumulated post-retirement benefit obligation, end of year	**61**	63
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**—**	—
Benefits paid	**(2)**	(2)
Employer contributions	**2**	2
Plan assets, end of year	**—**	—
Net amount recognized[a]	**(61)**	(63)

[a] $59 million is recognized in Regulatory and other liabilities and $2 million is recognized in Accounts payable and accrued charges on the Balance Sheets.

Other Post-Retirement Benefit Plans - Amounts Recognized in AOCI

($millions)	**December 31, 2016**	December 31, 2015
Net actuarial (gain) loss recognized in AOCI	**(6)**	(2)

($millions)	**2016**	2015
Other Post-Retirement Benefit Plans - Components of Net Periodic Benefit Cost		
Service cost benefit earned	**1**	2
Interest cost on accumulated post-retirement benefit obligation	**3**	2
Net periodic other post-retirement benefit cost	**4**	4
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial (losses) gains	**(4)**	(6)
Total recognized in other comprehensive income	**(4)**	(6)
Total recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**—**	(2)

Other Post-Retirement Benefits Plans - Assumptions Used for Benefits Accounting

	2016	2015
Benefit Obligations		
Discount rate for post-retirement plans	**3.81%**	4.03%
Salary increase	**3.00%**	3.00%
Net Periodic Benefit Cost		
Discount rate for post-retirement plans	**4.03%**	4.00%
Salary increase	**3.00%**	3.25%

The discount rates used to determine the post-retirement obligations are the rates at which the benefit obligations could be effectively settled. The discount rates for the plans are developed from yields on available high-quality bonds in Canada and reflect each plan's expected cash flows.

Assumed Health Care Cost Trend Rates

	2016	2015
Health care cost trend rate assumed for next year	**5.00%**	5.50%
Rate to which the cost trend rate is assumed to decline	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**2017**	2017

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

($millions)	**1% Point Increase**	1% Point Decrease
Effect on post-retirement benefit obligations	**3**	(3)

Other Post-Retirement Benefit Plans - Payments and Receipts

The Company expects to make future benefit payments, which reflect expected future service, as appropriate. The following benefit payments are expected to be paid over each of the next five years and thereafter.

($millions)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022-2026**
Expected benefit payments	2	3	3	3	3	16

Retirement/Savings Plan

The Company has employee savings plans available to eligible employees. Employees may participate in a matching contribution where the Company matches a certain percentage of before tax employee contributions of up to 5% of eligible pay per pay period. The Company expensed pre-tax employer matching contributions of $8 million in both the twelve months ended December 31, 2016 and 2015.

13. Asset Retirement Obligations

The Company's AROs relate to the legal obligation to disconnect, purge and cap abandoned pipelines, capping abandoned storage wells, and in some buildings, special handling and disposition of asbestos if it is disturbed.

The Company has non-asbestos AROs which include easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to the non-asbestos ARO because the fair value of the ARO cannot be reasonably estimated. The Company's pipeline system is considered a critical component of its business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term. The Company has determined that sufficient information to estimate the fair value of an ARO is not available because the assets are considered permanent with indeterminate useful lives and that sufficient information is not available to estimate a range of potential settlement dates in order to employ a present value technique to estimate fair value.

AROs are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

($millions)	**December 31, 2016**	December 31, 2015
Balance, beginning of year	**440**	368
Accretion expense	**20**	17
Liabilities settled	**(7)**	(7)
Revisions in estimated cash flows	**(36)**	62
Balance, end of year	**417**	440

14. Fair Value Measurements

Financial instruments recorded at fair value on the Balance Sheets are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of the Company's financial instruments that are actively traded in the secondary market are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency. The fair value of the Company's pension plan assets designated as Level 2 financial instruments is determined through the market approach valuation technique using observable inputs including matrix pricing and market corroborated pricing.

Level 3 Valuation Techniques

Level 3 valuation techniques include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation. The fair value of the Company's pension plan assets designated as Level 3 financial instruments is determined through the market approach valuation technique using unobservable inputs including investment manager pricing for private placements and private equities.

There were no transfers between levels during the year ended December 31, 2016.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts that could have been realized in current markets.

	December 31, 2016		December 31, 2015	
($millions)	**Book Value**	**Fair Value**	Book Value	Fair Value
Long-term debt, including current maturities[a]	**3,440**	**3,888**	3,140	3,538

[a] Excludes unamortized items.

The fair value of the Company's Long-term debt is determined based on market-based prices as described in the Level 2 valuation technique described above.

The fair values of Cash and cash equivalents, Accounts receivable, net, Accounts payable and accrued charges, Short-term borrowings and Commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligations. The maximum exposure to credit risk for the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement cost of gas loans at December 31, 2016 is $84 million receivable (2015 – $51 million receivable). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

The Company manages its credit risk on Cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on Accounts receivable, net the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2016 amounted to $39 million (2015 – $40 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

The Company continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31, 2016**	December 31, 2015
Current	**275**	218
30 Days over due	**10**	10
60 Days over due	**3**	4
90+ Days over due	**6**	11
Total trade accounts receivable	**294**	243
Allowance for doubtful accounts	**(5)**	(6)
Total trade accounts receivable, net[a]	**289**	237

[a] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

For the years ended December 31, 2016 and 2015, no one customer accounted for more than 10% of sales or 10% of receivables.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 10).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2016:

($millions)	Total	2017	2018-2019	2020-2021	Thereafter
Commercial paper	333	333	—	—	—
Accounts payable and accrued charges	878	878	—	—	—
Long-term debt (including principal and interest)	5,961	297	686	459	4,519
Total	7,172	1,508	686	459	4,519

15. Stock Based Compensation

The Spectra Energy 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 53 million shares of common stock may be awarded under the 2007 LTIP. Union Gas employees participate in the 2007 LTIP.

Stock based performance awards generally vest over three years at the earliest, if performance metrics are met. Spectra Energy granted 35,950 performance awards in 2016, 36,100 in 2015, and 38,200 in 2014, with fair values of U.S. $2 million for 2016, 2015 and 2014 to Union Gas employees. The total fair value of performance awards vested was U.S. $1 million in both 2016 and 2014. No performance awards vested in 2015. As of December 31, 2016, the Company expects to recognize U.S. $2 million of future compensation cost related to performance awards over a weighted-average period of less than one year.

Stock based phantom awards generally vest over three years. Spectra Energy awarded 34,575 phantom awards in 2016, 22,650 in 2015, and 24,200 in 2014, with fair values of U.S. $1 million for 2016, 2015, and 2014 to Union Gas employees. The total fair value of the phantom awards vested was U.S. $1 million in 2016, 2015 and 2014. As of December 31, 2016, the Company expects to recognize U.S. $1 million of future compensation cost related to phantom awards over a weighted-average period of less than two years.

Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of our common stock on the grant date, have ten-year terms and vest rateably over a three-year term. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. The Company issues new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model is used to estimate the fair value of options at grant date.

Stock Awards

	Performance Awards		Phantom Awards	
	Units	Weighted-Average Grant Date Fair Value U.S. $	Units	Weighted-Average Grant Date Fair Value U.S. $
Outstanding, beginning of year	120,103	39	75,097	26
Transfers out	(1,850)	42	(2,390)	31
Granted	35,950	53	34,575	29
Vested	(32,664)	33	(29,481)	30
Forfeited	(19,182)	37	(3,763)	34
Outstanding, end of year	102,357	49	74,038	39
Awards expected to vest	99,192	49	72,797	39

Stock Options

	Options	Weighted-Average Exercise Price U.S.$	Weighted-Average Remaining Life (in years)	Aggregate Intrinsic Value U.S.$ (in millions)
Outstanding at beginning of year	66,100	26	1.1	—
Granted	36,600	28	—	—
Exercised	(54,300)	26	—	—
Outstanding at end of year	48,400	28	6.9	1
Options exercisable at year-end	11,800	26	0.1	—

The Company awarded 36,600 non-qualified stock options to employees during 2016, with a fair value of U.S. $1 million. We did not award any non-qualified stock options to employees during 2015 or 2014.

Weighted-Average Assumptions for Option Pricing

	2016
Risk-free rate of return	1.4%
Expected life	6 years
Expected volatility	22.7%
Expected dividend yield	5.7%

The risk-free rate of return was determined based on a yield curve of U.S. Treasury rates ranging from six months to ten years and a period commensurate with the expected life of the options granted. The expected volatility was established based on historical volatility over six years using daily stock price observations. The expected dividend yield was determined based on the most recent annual dividend and the stock price at the time of grant.

As of December 31, 2016, future compensation costs related to stock options over a weighted-average period of less than 2 years was not significant.

16. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Balance Sheets. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company's potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

17. Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated.

In April 2016, the Ontario Ministry of the Environment and Climate Change (MOECC) issued a Director's Order (Order) naming the Company, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of the Company in Hamilton. The Order requires all parties to act jointly to develop a Conceptual Site Model (CSM) to fully delineate the extent of the soil and groundwater contamination and to assess remedial measures, if necessary. In May 2016, the Company appealed the Order, which should have been issued to the party responsible for the contamination and the owner of the source of the contamination, as opposed to those parties impacted by the contamination. In June 2016, the Environmental Review Tribunal (Tribunal), on consent of the MOECC's Director, stayed the application of parts of the Order on the condition that a Preliminary CSM (PCSM) be provided to the MOECC's Director, which in fact was delivered (with cooperation from the owners of the immediately adjacent owners, including the Company) in December 2016. The MOECC has provided its preliminary responses to the PCSM. In February 2017, the Tribunal extended the stay of the Order until May 9, 2017, pending a technical conference to be attended by the MOECC and the owners of the immediately adjacent properties in order to determine next steps. The risk of material environmental liability is unknown at this time. No amount has been accrued.

Other than the potential contingency noted above, of which the impact is unknown, the Company has no reason to believe that the ultimate outcome of these matters could have a significant impact on its Financial Statements.

18. Subsequent Events

Management has evaluated significant events and transactions that occurred from January 1, 2017 through February 26, 2017. On January 31, 2017, the Company received a $30 million capital contribution from GLBE in respect of the common shares of the Company.

DIRECTORS

David G. Unruh
Stephen W. Baker
Bruce E. Pydee

OFFICERS

Stephen W. Baker
Chair and President

J. Patrick Reddy
Chief Financial Officer

David G. Simpson
Vice President, Regulatory, Lands and Public Affairs

Tanya Mushynski
Vice President and General Counsel

Janice L. Ferguson
Vice President, Human Resources

James G. Redford
Vice President, Business Development - Storage and Transmission

Paul Rietdyk
Vice President, Engineering, Construction and Storage and Transmission Operations

Michael G.P. Shannon
Vice President, Distribution Operations

Wendy H. Zelond
Vice President, Finance

Laura J. Buss Sayavedra
Vice President and Treasurer

Timothy J. Kennedy
Vice President, Government and Aboriginal Affairs

Mark J. Isherwood
Vice President, In-Franchise Sales, Marketing and Customer Care

Edward J. Koval
Vice President, Supply Chain

Paul K. Haralson
Assistant Treasurer

Annachiara Jones
Corporate Secretary

Kelly L. Gray
Assistant Corporate Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **CST Trust Company**

Union Gas Limited preferred stock are listed on the Toronto Stock Exchange
Class A Preferred, Series A - 5½% (UNG.PR.C)

Class A Preferred, Series B - 6% (UNG.PR.D)

REGISTERED OFFICE
50 Keil Drive North
Chatham, Ontario N7M 5M1

The Financial Statements and all information in this report have been prepared by and are the responsibility of management. The Financial Statements have been prepared in conformity with generally accepted accounting principles in the United States of America and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon Union Gas Limited's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors (the Board) is responsible for ensuring that management fulfils its responsibility for financial reporting and for final approval of the Financial Statements.

The Board meets regularly with management, the internal auditors and the shareholders' auditors to review the Financial Statements, the Independent Auditor's Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Board, as does the Director of Internal Audit Services.

PricewaterhouseCoopers LLP performed an independent audit of the 2017 Financial Statements, as described in their Independent Auditor's Report.

Deloitte LLP performed an independent audit of the 2016 Financial Statements, as described in their Independent Auditor's Report, included in the 2016 Annual Report.

February 16, 2018

Stephen W. Baker	Wendy H. Zelond
President	Vice President, Finance

February 16, 2018

Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying financial statements of Union Gas Limited, which comprise the balance sheet as at December 31, 2017 and the statement of operations and comprehensive income, equity, and cash flows for the year then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2017 and its results of operations and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Other matter

The financial statements at December 31, 2016 and for the year then ended, were audited by another auditor who expressed an unmodified opinion on those consolidated financial statements in their report dated February 26, 2017.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the Years Ended December 31 ($millions)	**2017**	2016
Revenues		
Gas sales and distribution revenue	**1,873**	1,529
Storage and transportation revenue (note 11)	**363**	299
Other revenue	**24**	21
Total Revenues	**2,260**	1,849
Expenses		
Gas commodity, storage and transportation costs (note 11)	**1,070**	738
Operating and maintenance (note 11)	**428**	414
Depreciation and amortization	**265**	239
Property taxes and other	**75**	71
Total Expenses	**1,838**	1,462
Income before interest and income taxes	**422**	387
Interest expense (notes 11 and 12)	**171**	161
Income before income taxes	**251**	226
Income tax expense (note 6)	**16**	21
Net income	**235**	205
Preferred shares dividends	**3**	3
Net income applicable to common shares	**232**	202
Other comprehensive loss, net of tax		
Pension and benefits impact (net of tax of (3) and (3) respectively) (note 15)	**(9)**	(7)
Comprehensive income applicable to common shares	**223**	195

The accompanying notes are an integral part of these Financial Statements.

BALANCE SHEETS

As at December 31 ($millions)	**2017**	2016
Assets		
Current assets		
Cash and cash equivalents	**19**	27
Restricted cash (note 3)	**13**	15
Accounts receivable and other (notes 2, 4 and 11)	**759**	801
Income taxes receivable (note 6)	**38**	29
Inventories (note 2 and 5)	**163**	245
Total current assets	**992**	1,117
Property, plant and equipment, net (note 7)	**6,913**	6,426
Intangible assets, net (note 8)	**368**	82
Regulatory and other assets (notes 2 and 9)	**643**	602
Total Assets	**8,916**	8,227
Liabilities and Equity		
Current liabilities		
Short-term borrowings (note 11)	**—**	253
Commercial paper (note 12)	**485**	333
Accounts payable and accrued charges (notes 10 and 11)	**730**	878
Current maturities of long-term debt (note 12)	**400**	125
Total current liabilities	**1,615**	1,589
Long-term liabilities		
Long-term debt (note 12)	**3,393**	3,295
Deferred income taxes (note 6)	**564**	516
Asset retirement obligations (note 16)	**399**	417
Regulatory and other liabilities (notes 2 and 9)	**884**	602
Total long-term liabilities	**5,240**	4,830
Total Liabilities	**6,855**	6,419
Preferred Shares (note 13)	**110**	110
Equity		
Common shares, unlimited shares authorized, 57,822,650 outstanding (note 14)	**657**	627
Retained earnings	**1,485**	1,253
Accumulated other comprehensive loss	**(195)**	(186)
Paid-in capital	**4**	4
Total Equity	**1,951**	1,698
Total Liabilities and Equity	**8,916**	8,227

The accompanying notes are an integral part of these Financial Statements.

Approved by the Board

Director

Director

STATEMENTS OF CASH FLOWS

For the Years Ended December 31 ($millions)	**2017**	2016
Operating Activities		
Net income	**235**	205
Items not affecting cash		
Depreciation and amortization	**268**	239
Loss on disposal of assets	**—**	1
Deferred income taxes	**(17)**	8
Changes in working capital (note 20)	**238**	(14)
Net cash provided by operating activities	**724**	439
Investing Activities		
Additions to property, plant and equipment	**(725)**	(1,012)
Additions to intangibles	**(305)**	(24)
Net cash used in investing activities	**(1,030)**	(1,036)
Financing Activities		
Net (decrease) increase in short-term borrowings	**(253)**	197
Net increase in commercial paper	**152**	126
Long-term debt issued, net of issue costs	**497**	499
Long-term debt repayments	**(125)**	(200)
Capital contribution received	**30**	—
Dividends paid	**(3)**	(3)
Net cash provided by financing activities	**298**	619
Change in cash and cash equivalents, during the year	**(8)**	22
Cash and cash equivalents, beginning of year	**27**	5
Cash and cash equivalents, end of year	**19**	27
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest, net of amounts capitalized	**169**	158
Cash payments of income taxes, net of refunds received	**34**	9
Property, plant and equipment noncash accruals	**9**	24

The accompanying notes are an integral part of these Financial Statements.

STATEMENTS OF EQUITY

($millions)	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Paid-in Capital	Total
December 31, 2016	627	1,253	(186)	4	1,698
Net income	—	235	—	—	235
Other comprehensive loss	—	—	(9)	—	(9)
Capital contribution received (note 14)	30	—	—	—	30
Dividends					
Preferred shares	—	(3)	—	—	(3)
December 31, 2017	657	1,485	(195)	4	1,951
December 31, 2015	627	1,051	(179)	4	1,503
Net income	—	205	—	—	205
Other comprehensive loss	—	—	(7)	—	(7)
Dividends					
Preferred shares	—	(3)	—	—	(3)
December 31, 2016	627	1,253	(186)	4	1,698

The accompanying notes are an integral part of these Financial Statements.

UNION GAS LIMITED
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2017 AND 2016

1. Summary of Operations and Significant Accounting Policies

The terms "Union Gas" or "the Company" as used in these Financial Statements refer to Union Gas Limited unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. Union Gas' common shares are held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

On February 27, 2017 Enbridge Inc. (Enbridge) and Spectra Energy completed a stock-for-stock merger transaction (the Merger) pursuant to which Enbridge acquired all of the issued and outstanding common shares of Spectra Energy. As a result of the Merger, Enbridge and its subsidiaries own Union Gas through their ownership of Spectra Energy.

Nature of Operations

Union Gas owns and operates natural gas distribution, storage and transmission facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy market participants. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the distribution, storage and transportation of natural gas.

Basis of Presentation

The Financial Statements of the Company include the standalone accounts of the Company and have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). All amounts are presented in millions of Canadian dollars except where noted.

In 2014, Canadian securities regulators approved the extension of the Company's exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

Use of Estimates

The preparation of the Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities. Significant estimates and assumptions used in the preparation of the Financial Statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities; unbilled revenues; depreciation rates and carrying value of property, plant and equipment; amortization rates and carrying value of intangible assets; fair value of financial instruments; provisions for income taxes; assumptions used to measure retirement and Other Postretirement Benefits (OPEB); commitments and contingencies; and fair value of Asset Retirement Obligations (ARO). Actual amounts could differ from these estimates.

Regulation

The Company is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act, (1998)*. This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within the Company and provides the framework required to support new storage investments.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and its ability to achieve forecasted revenues and manage costs.

Effective January 1, 2014, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts.

As part of the Company's OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings in excess of 100 basis points above the benchmark return on equity are shared with ratepayers as a reduction in earnings during the year, if applicable.

The Company follows U.S. GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered and collection is reasonably assured. Revenues related to these services provided or products delivered but not yet billed are estimated each month. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise areas.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred on the Balance Sheets for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the cost of gas an estimated amount of these differences based upon the methodology used by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Derivative Instruments and Hedging

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in currency exchange rates related to unregulated storage revenues. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded under Other comprehensive income/loss (OCI) and is reclassified to earning when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and is recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

The Company recognizes the fair value of derivative instruments on the Balance Sheet as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Statement of Cash Flows.

Income Taxes

The liability method of accounting for income taxes is followed. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For the Company's regulated operations, a deferred income tax liability is recognized with a corresponding regulatory asset to the extent taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

Inventories

Gas in storage for resale to customers is carried at reference prices approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred on the Balance Sheets for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment is stated at historical cost less accumulated depreciation and amortization. The Company capitalizes all construction-related direct labour and material costs, as well as indirect construction costs. Indirect costs include general engineering and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred.

Regulated depreciation is computed based on the asset's average service life using the straight-line method. Unregulated depreciation is computed based on management's assumption of useful life using the straight-line method.

When regulated property, plant and equipment is retired, the original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation and amortization. When entire regulated operating units are sold or non-regulated property, plant and equipment is retired, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Intangible Assets

Intangible assets consists of computer software and greenhouse gas (GHG) compliance instruments. The GHG compliance instruments are purchased by the Company for itself and most of its customers in order to meet Cap and Trade compliance obligations in the Province of Ontario (the Province). Purchased GHG compliance instruments are recorded at their original cost and are not amortized, as they will be used to satisfy compliance obligations as they come due. Computer software is amortized on a straight line basis.

Asset Retirement Obligations

The Company recognizes AROs for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within the Company's control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

Stock-Based Compensation

Union Gas employees participate in a stock-based compensation plan sponsored by Enbridge, subsequent to the Merger. For employee awards, equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests, the date the employee becomes retirement-eligible, or the date the award market condition is met. Awards, including stock options, granted to employees that are already retirement-eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

Pension and Other Postretirement Benefits

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality.

The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. Net benefit cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Interest cost of pension plan obligations;
- Expected return on pension plan assets;

- Amortization of the prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between actual vs. expected plan experience, which include differences between the expected rate of return on plan assets and the actual rate of return for that period, differences in salary, inflation, retirement and termination experience. The actuarial gains and losses also include the impact of changes in the actuarial assumptions used to determine the accrued benefit obligation from one year end to the other.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

The Company also maintains supplemental pension plans that provide pension benefits in excess of the basic plans for certain employees.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides Postretirement benefits other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and Postretirement benefit plans is recognized as Regulatory and other assets, Accounts payable and accrued charges, or Regulatory and other liabilities on the Balance Sheets. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax, until they are amortized to be recognized as a component of benefit expense within Operating and maintenance expenses in the Statements of Operations and Comprehensive Income. See note 15 for further discussion.

Commitments and Contingencies

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or a liability has been incurred, and the amount of the impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probably loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

New Accounting Pronouncements

Revenue from Contracts with Customers

Accounting Standards Update (ASU) 2014-09 was issued in May 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. It also requires the use of more estimates and judgments than the present standards in addition to additional disclosures. The new standard is effective January 1, 2018. The new standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. The Company has decided to adopt the revenue standard using the modified retrospective method.

The Company has reviewed its revenue contracts in order to evaluate the effect of the new standard on its revenue recognition practices. Based on this assessment, the Company does not anticipate any material differences in the amount or timing of revenue recognition under the new standard.

In addition, the Company is in the process of implementing appropriate changes to business processes, systems and controls to support the recognition and disclosure requirements of the new standard and has developed and tested processes to generate the new disclosures which will be required commencing in the first quarter of 2018.

Recognition and Measurement of Financial Assets and Liabilities

ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation and disclosure of financial assets and liabilities. Investments in equity securities, excluding equity method and consolidated investments, are no longer classified as trading or available-for-sale securities. All investments in equity securities with readily determinable fair values are classified as investments at fair value through net income. Investments in equity securities without readily determinable fair values are measured using the fair value measurement alternative, and are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investments of the same issuer. Investments in equity securities measured using the fair value measurement alternative are reviewed for indicators of impairment each reporting period. Fair value of financial instruments for disclosure purposes is measured using exit price. The accounting update is effective January 1, 2018 and will be applied on a prospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the Company's Financial Statements.

Recognition of Leases

ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations. It requires lessees of operating lease agreements to recognize key lease assets and lease liabilities on the Balance Sheet and disclose additional key information about lease agreements. The accounting update also replaces the current definition of a lease and requires that an arrangement be recognized as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. The Company is currently gathering a complete inventory of its lease contracts in order to assess the impact of the new standard on the Company's Financial Statements. The accounting update is effective January 1, 2019 and will be applied using a modified retrospective approach.

Improvements to Employee Share-Based Payment Accounting

Effective January 1, 2017, the Company adopted ASU 2016-09 and applied certain amendments on a modified retrospective basis with the remaining amendments applied on a prospective basis. The new standard was issued with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the Statement of Cash Flows. The adoption of the pronouncement did not have a material impact on the Company's Financial Statements.

Accounting for Credit Losses

ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. The Company is currently assessing the impact of the new standard on the Company's Financial Statements. The accounting update is effective January 1, 2020.

Simplifying Cash Flow Classification

ASU 2016-15 was issued in August 2016 with the intent of reducing diversity in practice of how certain cash receipts and cash payments are classified in the Statement of Cash Flows. The new guidance addresses eight specific presentation issues. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. The Company has assessed the eight specific presentation issues and the adoption of this accounting standard does not have a material impact on the Company's Financial Statements.

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows

ASU 2016-18 was issued in November 2016 with the intent to clarify guidance on the classification and presentation changes in Restricted cash and restricted cash equivalents within the Statement of Cash Flows. The amendments require that changes in Restricted cash and restricted cash equivalents be included with Cash and cash equivalents when reconciling the opening and closing period amounts shown on the Statement of Cash Flows. The Company currently presents the changes in Restricted cash and restricted cash equivalents under operating activities in the Statement of Cash Flows. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. The Company will amend the presentation in the Statement of Cash Flows to include restricted cash and restricted cash equivalents with Cash and cash equivalents and the Company will retrospectively reclassify all periods presented.

Improving the Presentation of Net Periodic Benefit Cost related to Defined Benefit Plans

ASU 2017-07 was issued in March 2017 primarily to improve the income statement presentation of the components of net periodic pension cost and net periodic postretirement benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. In addition, only the service-cost component of net benefit cost is eligible for capitalization. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis for the income statement presentation component and on a prospective basis for the capitalization component. The Company does not expect the adoption of this accounting update to have a material impact on the Company's Financial Statements.

Clarifying Guidance on the Application of Modification Accounting on Stock Compensation

ASU 2017-09 was issued in May 2017 with the intent to clarify the scope of modification accounting and when it should be applied to a change to the terms or conditions of a share based payment award. Under the new guidance, modification accounting is required for all changes to share based payment awards, unless all of the following are met: 1) there is no change to the fair value of the award, 2) the vesting conditions have not changed, and 3) the classification of the award as an equity instrument or a debt instrument has not changed. The accounting update is effective January 1, 2018 and will be applied on a prospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the Company's Financial Statements.

2. Regulatory Matters

Regulatory Assets and Liabilities

The Company recorded the following assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	**December 31, 2017**	December 31, 2016	Recovery/Settlement Period
Regulatory assets[(a)]				
Non-gas commodity deferrals	Accounts receivable and other	**74**	82	Less than 1 year
Gas in storage inventory[(b)]	Inventories	**—**	13	Less than 1 year
Deferred income taxes – long-term[(c) (d)]	Regulatory and other assets	**530**	462	Over the remaining life of the assets
Total regulatory assets		**604**	557	
Regulatory liabilities[(a)]				
Deferred income taxes – current[(c)]	Accounts payable and accrued charges	**7**	7	Less than 1 year
Non-gas commodity deferrals	Accounts payable and accrued charges	**16**	16	Less than 1 year
Gas cost deferrals[(e)]	Accounts payable and accrued charges	**4**	13	Less than 1 year
Gas in storage inventory[(b)]	Inventories	**21**	—	Less than 1 year
Asset removal costs[(c) (f)]	Regulatory and other liabilities	**432**	394	Over the remaining life of the assets
Total regulatory liabilities		**480**	430	

(a) All regulatory assets and liabilities are excluded from rate base unless otherwise noted.

(b) Gas in storage is recorded at reference prices approved by OEB. In the absence of rate-regulation, inventory would be valued at the lower of cost or market value.

(c) All or a portion of the balance is included in rate base.

(d) Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since substantially all of these timing differences are related to property, plant and equipment costs, recovery of these regulatory assets is expected to occur over the life of those assets.

(e) These regulatory liabilities represent gas cost collections from customers under approved rates that vary from the actual cost of gas for the associated periods. The Company files an application quarterly with the OEB to ensure that customers' rates are updated to reflect published forward-market prices. The difference between the approved and actual cost of gas is deferred for future repayment to or refund from customers.

(f) These regulatory liabilities represent collections from customers under approved rates for future asset removal activities that are expected to occur associated with its regulated facilities.

Rate Related Information

The Company's distribution rates, beginning January 1, 2014 are set under a five-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation,
- rate increases or decreases in the small volume customer classes where average use declines or increases,

- certain adjustments to base rates,
- the continued pass-through of gas commodity, upstream transportation and demand side management costs,
- the additional pass-through of costs associated with major capital investments and certain fuel variances,
- an allowance for unexpected cost changes that are outside of management's control,
- equal sharing of tax changes between the Company and its customers, and
- an earnings sharing mechanism that permits the Company to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.

Annual Non-Gas Commodity Deferral Accounts Disposition

Non-gas commodity deferral accounts are filed for approval of disposition annually and typically collected or recovered over six months. In August 2017, the OEB approved collection of the 2016 non-gas commodity deferral account balances of $43 million beginning October 1, 2017.

Demand Side Management (DSM)

In December 2017, after receiving final audit results, the Company filed an application with the OEB for the disposition of the 2015 DSM deferral account balances. The impact is a net receivable from customers of approximately $8 million. Union Gas has requested a decision from the OEB in the first quarter of 2018 to allow recovery from customers to begin in the second quarter of 2018.

Application to Amalgamate

In November 2017, the Company and Enbridge Gas Distribution Inc. (EGD), an affiliate of the Company, (together, the Applicants) filed an application with the OEB to amalgamate, in accordance with the OEB's guidance for Mergers, Acquisitions, Amalgamations and Divestitures (MAAD), with an effective date of January 1, 2019. Under the OEB's MAAD policy, the Applicants are seeking to defer rate rebasing for ten years to allow the utilities to identify and leverage best practices and implement integrated solutions. This filing initiated the regulatory review process which will continue through 2018 with a decision from the OEB expected in the second half of 2018.

Subsequent to the above application, also in November 2017, Union Gas and EGD submitted a second, related, application. The application seeks an order approving a rate setting mechanism for the ten year rebasing period effective January 1, 2019 that would apply if Enbridge proceeds with the amalgamation of the Company and EGD. The Applicants are seeking approval of a price cap mechanism which includes an annual rate escalation at inflation; continues to pass through certain costs; allows for pass through of capital expenditures in excess of an OEB approved threshold; and allows for non-routine adjustments with a materiality threshold of $1 million.

The final decision on whether to proceed with the amalgamation is subject to the completion of the regulatory process and Union Gas, EGD, and Enbridge's review and assessment of the regulatory outcomes and their respective Board of Directors approvals.

3. Restricted Cash

The Company had $13 million of restricted funds at December 31, 2017. At December 31, 2016, the Company had $37 million of restricted funds, with $15 million classified as Restricted cash and $22 million classified as Regulatory and other assets. These restricted funds are related to money received from the Province under the Green Investment Fund (GIF) program. The purpose of the GIF program is to reduce the GHG emissions in the residential sector. The Company's use of the funds is limited to eligible capital expenditures for the purpose of executing the program. The Company will manage the GIF program separately from its core regulated activities. There is no earnings impact relating to the GIF program. Any unspent funds must be returned to the Province at the expiry of the agreement on May 31, 2019, or should the Province elect to terminate the agreement at any time prior to is expiration date.

Changes in restricted balances are presented within Operating Activities on the Company's Statements of Cash Flows.

4. Accounts Receivable and Other

($millions)	**December 31, 2017**	December 31, 2016
Trade receivables	**209**	161
Unbilled revenue	**202**	133
Gas imbalances[a]	**251**	410
Regulatory assets – current	**74**	82
Other	**29**	20
Allowance for doubtful accounts	**(6)**	(5)
Total Accounts receivable and other	**759**	801

[a] The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Balance Sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

5. Inventories

Gas in storage includes gas for delivery to customers and for use in the Company's operations. Inventories of materials and supplies are for use in the Company's operations.

($millions)	**December 31, 2017**	December 31, 2016
Gas in storage	**140**	222
Materials and supplies	**23**	23
Total Inventories	**163**	245

6. Income Taxes

Income Tax Rate Reconciliation

($millions)	**2017**	2016
Income before income taxes	**251**	226
Canadian federal statutory income tax rate	**15.0%**	15.0%
Expected federal taxes at statutory rate	**38**	34
Increase (decrease) resulting from:		
Provincial income taxes	**—**	5
Part VI.1 tax, net of federal Part 1 deduction	**8**	5
Deferred income tax adjustments related to rate regulated operations	**(31)**	(25)
Other	**1**	2
Income tax expense	**16**	21
Effective income tax rate	**6.4%**	9.3%

Components of Pretax Earnings and Income Taxes

($millions)	**2017**	2016
Current income taxes	**33**	13
Deferred income taxes (recovery) expense	**(17)**	8
Income taxes expense	**16**	21

Components of Deferred Income Taxes

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

($millions)	**December 31, 2017**	December 31, 2016
Deferred income tax liabilities		
Property, plant and equipment	**(445)**	(405)
Regulatory assets	**(139)**	(121)
Other	**(15)**	(22)
Total deferred income tax liabilities	**(599)**	(548)
Deferred income tax assets		
Pension	**35**	32
Total deferred income tax assets	**35**	32
Net deferred income tax liabilities	**(564)**	(516)

Unrecognized Tax Benefits

($millions)	**December 31, 2017**	December 31, 2016
Unrecognized tax benefits at beginning of year	**38**	28
Gross increases related to prior year tax positions	**7**	8
Gross decreases related to prior year tax positions	**(2)**	—
Gross increases related to current year tax positions	**3**	3
Reductions due to lapse of statute of limitations	**(1)**	(1)
Unrecognized tax benefits at end of year	**45**	38

The unrecognized tax benefits as at December 31, 2017, if recognized, would reduce the Company's annual effective income tax rate. Although uncertain, the Company believes it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $35 million prior to December 31, 2018. The anticipated changes in unrecognized tax benefits relate to the expiration of statutes of limitations and expected audit settlements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the year ended December 31, 2017 included $nil (2016 – $nil) interest and penalties. As at December 31, 2017, interest and penalties of $1 million (2016 – $1 million) have been accrued.

The Company remains subject to examination for income tax returns for years 2009 through 2016.

7. Property, Plant and Equipment, net

($millions)	Useful Life	**December 31, 2017**	December 31, 2016
	(years)		
Plant			
Natural gas transmission	20 - 58	**3,242**	2,734
Natural gas distribution	25 - 60	**4,887**	4,697
Storage	10 - 50	**1,187**	924
Land rights and rights of way	48 - 61	**141**	137
Other buildings and improvements	2 - 42	**63**	62
Equipment	4 - 15	**80**	82
Vehicles	6	**60**	57
Land	—	**94**	90
Construction in progress	—	**40**	349
Other	15 - 18	**17**	21
Total Property, plant and equipment		**9,811**	9,153
Total accumulated depreciation and amortization		**2,898**	2,727
Total Property, plant and equipment, net		**6,913**	6,426

The Company had no capital leases at December 31, 2017 or 2016.

96% of the Company’s property, plant and equipment is regulated with estimated useful lives based on rates approved by the OEB. Composite weighted-average depreciation rates were 2.73% for 2017 and 2.76% for 2016.

The Company capitalized interest of $8 million in 2017 and $11 million in 2016.

8. Intangible Assets, net

($millions)	**December 31, 2017**	December 31, 2016
Intangible assets	**410**	116
Less: Accumulated amortization	**42**	34
Intangible assets, net	**368**	82

Intangible assets consists of computer software and GHG compliance instruments. As of January 31, 2017, GHG compliance instruments were purchased by the Company for itself and most of its customers in order to meet Cap and Trade compliance obligations in the Province. Purchased GHG compliance instruments are recorded at their original cost and are not amortized, as they will be used to satisfy compliance obligations as they come due. Computer software is amortized on a straight line basis over a period of 4 – 10 years.

The Company capitalized interest of $nil in 2017 and $1 million in 2016 related to software.

All of the Company's computer software was developed or obtained for internal use.

Amortization expense of intangible assets totaled $19 million in 2017 and $15 million in 2016. Estimated amortization expense for the next five years is as follows:

($millions)	**2018**	**2019**	**2020**	**2021**	**2022**
Estimated amortization expense	21	19	17	10	4

9. Regulatory and Other Assets and Liabilities

($millions)	**December 31, 2017**	December 31, 2016
Deferred income taxes – long-term (note 2)	**530**	462
Restricted cash	**—**	22
Goodwill	**12**	12
Pension assets	**33**	27
Balancing gas	**56**	67
Major spare parts	**10**	10
Other	**2**	2
Total Regulatory and other assets	**643**	602
Asset removal costs (note 2)	**432**	394
Pension liabilities	**167**	147
Unrecognized tax benefits	**45**	38
GIF payable	**—**	22
GHG compliance liabilities[a]	**238**	—
Other	**2**	1
Total Regulatory and other liabilities	**884**	602

[a] Under Cap and Trade regulation in the Province, the Company is required to meet GHG compliance obligations for most of its customers' use of natural gas as well as for emissions from its own operations. The Company will be required to relieve its compliance liability through the submission of compliance instruments following the completion of the initial compliance period of January 1, 2017 through December 31, 2020.

10. Accounts Payable and Accrued Charges

($millions)	**December 31, 2017**	December 31, 2016
Gas imbalances[a]	**251**	410
Accrued liabilities	**199**	170
Trade payables	**127**	142
Security deposits	**43**	39
Interest payable	**37**	37
Contractual holdbacks	**27**	34
Regulatory liabilities – current	**27**	36
Taxes payable	**19**	10
Total Accounts payable and accrued charges	**730**	878

[a] The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Balance Sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

11. Related Party Transactions

The Company occasionally performs services for and incur costs on behalf of Enbridge, Spectra Energy and its affiliates (related parties), which are subsequently reimbursed. Likewise, certain related parties may perform services for or incur costs on behalf of the Company, which are then reimbursed by the Company. The Company also provides and purchases gas, storage and transportation services to related parties. These transactions are in the normal course of operations and are recorded at exchange amounts agreed to between the related parties.

In addition, related parties perform centralized corporate functions for the Company, pursuant to agreements with related parties, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. The Company reimburses related parties for the expenses to provide these services as well as other expenses they incur on the Company's behalf. Related parties charge such expenses based on the cost of actual services provided or using various allocation methodologies based on the Company's percentage of assets, employees, earnings or other measures, as compared to Enbridge and Spectra Energy's other related parties.

In the normal course of operations, the Company provides or obtains funds from Westcoast on an unsecured basis. The Company also has a promissory note to borrow up to $150 million from GLBE on an unsecured basis.

On July 31, 2017, the Company entered into a Gas Storage Service Agreement (GSSA) with EGD, a new affiliated company under common control as a result of the Merger, whereby the Company contracted all of EGD's unregulated storage space and deliverability effective September 2017. In conjunction with the GSSA, the Company entered into a Storage Contracts Assignment Agreement with EGD whereby the Company took assignment of EGD's customer contracts related to the assigned unregulated storage space, effective September 2017. On September 29, 2017, EGD novated all of its derivative instruments relating to foreign exchange forward contracts to the Company.

The Company's transactions with related parties are as follows:

($millions)	Storage and transportation revenue	Gas commodity, storage and transportation expense	Shared service charges (receipts)[a]	Total
2017				
St Clair Pipelines Partnership, a division of Westcoast	—	1	—	1
Pipeline and Field Services, a division of Westcoast	—	—	(4)	(4)
Westcoast Energy Inc.	—	—	(1)	(1)
Spectra Energy Gas Transmission LLC	—	—	12	12
Sarnia Airport Storage Pool Limited Partnership	(1)	5	—	4
Market Hub Partners L.P.	—	1	—	1
Enbridge Gas Distribution Inc.	(113)	7	—	(106)
Tidal Energy Marketing Inc.	(4)	—	—	(4)
Tidal Energy Marketing (US) LLC	—	5	—	5
St. Lawrence Gas Company Inc.	(1)	—	—	(1)
Express-Platte Pipeline L.P.	—	—	(1)	(1)
Total	(119)	19	6	(94)
2016				
St Clair Pipelines 1996, a division of Westcoast	—	—	(2)	(2)
Pipeline and Field Services, a division of Westcoast	—	—	(4)	(4)
Spectra Energy Empress L.P.	—	21	—	21
Spectra Energy Gas Transmission LLC	—	—	21	21
Sarnia Airport Storage Pool Limited Partnership	—	4	—	4
Total	—	25	15	40

[a]Excludes compensation arrangements.

Net amounts due from (to) related parties are as follows:

($millions), net	**2017**	2016
Enbridge Gas Distribution Inc.	**11**	—
Tidal Energy Marketing Inc.	**1**	—
Spectra Energy Gas Transmission LLC	**(4)**	(1)
Enbridge Inc.	**(2)**	—
Westcoast Energy Inc.	**—**	(253)
Other	**1**	—
Total[a]	**7**	(254)

[a]At December 31, 2017, $9 million (2016 – $5 million) is recognized in Accounts payable and accrued charges, $16 million (2016 – $4 million) is recognized in Accounts receivable and other, and $nil (2016 – $253 million) is recognized in Short-term borrowings on the Balance Sheets.

12. Debt and Credit Facilities

Summary of Debt and Related Terms

($millions)		**December 31, 2017**	December 31, 2016
9.70%	1992 Series II debentures, due November 6, 2017	—	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
2.76%	Series 11, due June 2, 2021	**200**	200
4.85%	Series 6, due April 25, 2022	**125**	125
3.79%	Series 10, due July 10, 2023	**250**	250
3.19%	Series 13, due September 17, 2025	**200**	200
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
2.81%	Series 14, due June 1, 2026	**250**	250
2.88%	Medium term note debentures, due November 22, 2027	**250**	—
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9, due June 21, 2041	**300**	300
4.20%	Series 12, due June 2, 2044	**500**	500
3.80%	Series 15, due June 1, 2046	**250**	250
3.59%	Medium term note debentures, due November 22, 2047	**250**	—
Long-term debt principal (including current maturities)		**3,815**	3,440
Less: Unamortized debt discount		**7**	7
Less: Debt issue costs		**15**	13
Add: Commercial paper		**485**	333
Total debt		**4,278**	3,753
Less: Current maturities of long-term debt		**400**	125
Less: Commercial paper		**485**	333
Total Long-term debt		**3,393**	3,295

The Company's long-term debt is unsecured. Principal repayment requirements on long-term debt are as follows:

($millions)	**Total**	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
Long-term debt[(a)]	3,815	400	—	—	200	125	3,090

[(a)] Excludes commercial paper of $485 million.

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2017 and 2016, the Company is in compliance with all such covenants.

Total interest expense on long-term debt in 2017 was $171 million (2016 – $169 million).

Available Credit Facility and Restrictive Debt Covenants

			Commercial Paper Debt Outstanding at	
($millions)	**Expiration Date**	**Credit Facility Capacity**	**December 31, 2017**	December 31, 2016
Multi-year syndicated [(a)]	2021	700	**485**	333

[(a)] The credit facility contains a covenant requiring the debt-to-total capitalization ratio, as defined in the agreement, to not exceed 75% and a provision which requires the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 67.6% at December 31, 2017 (December 31, 2016 – 69.0%). Commercial paper issuances, net of discount, are back-stopped by the credit facility.

The available credit facility carried a weighted average standby fee of 0.085% on the unused portion.

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2017 and December 31, 2016 there were no letters of credit issued or revolving borrowings outstanding under the credit facility. The majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2017 was 1.28% (2016 – 0.87%). The weighted average days to maturity on outstanding commercial paper as of December 31, 2017 was fourteen days (2016 – 8 days).

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2017 and December 31, 2016, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower.

Total interest paid on short term debt in 2017 was $6 million (2016 – $1 million).

The Company and certain affiliates have, in aggregate, access to a $400 million demand letter of credit facility. As of December 31, 2017, the Company had no outstanding letters of credit under this facility.

13. Preferred Shares

		Outstanding			
	Authorized	**December 31, 2017**	December 31, 2016	**December 31, 2017**	December 31, 2016
	(shares)	*(shares)*		*($millions)*	
Class A	202,072				
5.5% Series A		**47,672**	47,672	**3**	3
6% Series B		**90,000**	90,000	**5**	5
5% Series C		**49,500**	49,500	**2**	2
4.88% Class B, Series 10	Unlimited	**4,000,000**	4,000,000	**100**	100
				110	110

The Class A, Series A and Class A, Series C Preferred Shares are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

The Class A, Series B Preferred Shares are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preferred Shares are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares once every five years commencing

January 1, 2014. The holders of the Class B, Series 10 Preferred shares did not exercise their option on January 1, 2014 and their next optional conversion date is January 1, 2019. The Company may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2018.

The Company has an unlimited number of authorized 4.79% Class B, Series 11 Preferred Shares. These shares are cumulative and redeemable at $25 per share at the option of the Company, and at the option of the holders, convertible back into Series 10 shares, commencing on January 15, 2026 and on each fifth anniversary thereafter (each such anniversary, a Series 11 Conversion Date). Additionally, these shares are redeemable at $25.50 per share at the option of the Company on any date after January 15, 2026 that is not a Series 11 Conversion Date. At December 31, 2017 and December 31, 2016 none of these shares were issued or outstanding.

The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other type of securities other than Preferred shares. As these shares are not solely in the control of the Company, they have been classified as temporary equity on the Balance Sheets.

14. Share Capital

On January 31, 2017, the Company received a $30 million capital contribution from GLBE in respect of the Common shares of the Company. There were no Common shares issued as a result of this transaction.

15. Pension and Other Postretirement Benefits

Pension Plans

The Company maintains registered and non-registered, contributory and non-contributory pension plans which provide defined benefit and/or defined contribution pension benefits covering substantially all employees. The Company also maintains supplemental pension plans that provide pension benefits in excess of the basic plans for certain employees.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on each plan participant’s years of service and final average remuneration. The Company’s contributions are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities.

Defined Contribution Plans

Contributions are generally based on each plan participant’s age, years of service and current eligible remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

Other Postretirement Benefits

OPEB primarily includes supplemental health and dental, health spending accounts and life insurance coverage for qualifying retired employees on a non-contributory basis. The OPEB plans are not funded.

Benefit Obligation, Plan Assets and Funded Status

The following table details the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans.

	Pension		OPEB	
($millions)	**2017**	2016	**2017**	2016
Change in benefit obligation				
Benefit obligation, at beginning of year	**917**	877	**61**	63
Service cost	**23**	19	**1**	1
Interest cost	**35**	35	**2**	3
Actuarial loss (gain)	**43**	22	**2**	(4)
Participant contributions	**4**	4	**—**	—
Benefits paid	**(43)**	(40)	**(2)**	(2)
Plan amendments	**—**	—	**(1)**	—
Benefit obligation, end of year [(a)]	**979**	917	**63**	61
Change in plan assets				
Fair value of plan assets, beginning of year	**854**	842	**—**	—
Actual return on plan assets	**73**	47	**—**	—
Benefits paid	**(43)**	(40)	**(2)**	(2)
Employer contributions	**16**	4	**2**	2
Participant contributions	**4**	4	**—**	—
Expected non-investment expenses	**—**	(3)	**—**	—
Fair value of plan assets, end of year	**904**	854	**—**	—
Underfunded status at end of year	**(75)**	(63)	**(63)**	(61)

	Pension		OPEB	
($millions)	**2017**	2016	**2017**	2016
Underfunded status at end of year				
Current Liabilities – Other	**(2)**	(2)	**(2)**	(2)
Deferred Credits and Other Liabilities – Regulatory and Other	**(106)**	(88)	**(61)**	(59)
Other Assets – Other	**33**	27	**—**	—
Underfunded status at end of year	**(75)**	(63)	**(63)**	(61)

[(a)] For pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. The accumulated benefit obligation for the Company's pension plans was $917 million as at December 31, 2017 (2016 – $866 million).

At December 31, 2017, pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations of $574 million (2016 – $519 million), accumulated benefit obligations of $517 million (2016 – $475 million), and plan assets with a fair value of $466 million (2016 – $428 million).

Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)

The amounts of pre-tax AOCI relating to the Company's pension and OPEB plans are as follows:

	Pension		OPEB	
($millions)	**2017**	2016	**2017**	2016
Net actuarial loss (gain)	**269**	257	**(4)**	(6)
Prior service cost	**1**	2	**(1)**	—
Total amounts recognized in AOCI, pre-tax	**270**	259	**(5)**	(6)

Net Benefit Costs Recognized

The components of net benefit cost and other amounts recognized in pre-tax OCI related to the Company's pension and OPEB plans are as follows:

	Pension		OPEB	
($millions)	**2017**	2016	**2017**	2016
Net Benefit Costs				
Service cost	**23**	22	**1**	1
Interest cost	**35**	35	**2**	3
Expected return on plan assets	**(57)**	(57)	**—**	—
Amortization of actuarial loss and prior service cost	**15**	18	**—**	—
Net defined benefit and OPEB costs	**16**	18	**3**	4
Defined contribution benefit costs	**6**	6	**—**	—
Net benefit costs recognized	**22**	24	**3**	4
Amount recognized in Other Comprehensive Income				
Prior service cost	**—**	—	**(1)**	—
Net actuarial loss (gain) arising during the year	**26**	32	**2**	(4)
Amortization of actuarial loss and prior service cost	**(15)**	(18)	**—**	—
Total amount recognized in other comprehensive income	**11**	14	**1**	(4)
Total amount recognized in Comprehensive Income	**33**	38	**4**	—

The Company estimates that approximately $22 million related to pension plans and $nil related to OPEB plans at December 31, 2017 will be reclassified from AOCI into net income in the next 12 months.

Actuarial Assumptions

The weighted average assumptions made in the measurement of the benefit obligations and net benefit cost of the Company's pension and OPEB plans are as follows:

	Pension		OPEB	
	2017	2016	**2017**	2016
Benefit Obligations				
Discount rate	**3.53%**	3.81%	**3.58%**	3.81%
Rate of salary increase	**3.04%**	3.00%	**3.22%**	3.00%
Net Benefit Costs				
Discount rate	**3.81%**	4.03%	**3.81%**	4.03%
Rate of salary increase	**3.00%**	3.00%	**3.47%**	3.00%
Rate of return on plan assets	**6.90%**	7.15%	**N/A**	N/A

Assumed Health Care Cost Trend Rates

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	2017	2016
Health care cost trend rate assumed for next year	**5.37%**	5.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	**4.36%**	5.00%
Year that the rate reaches the ultimate trend rate	**2034**	2017

A 1% point change in the assumed health care cost trend rate would have the following effects for the year ended December 31, 2017:

($millions)	**1% Point Increase**	**1% Point Decrease**
Effect on total service and interest costs	**1**	**—**
Effect on accumulated postretirement benefit obligations	**2**	**(2)**

Plan Assets

Pension plan assets are maintained in a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trusts. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. The Company regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The asset allocation targets and major categories of plan assets are as follows:

Asset Category	**Target Allocation**	**December 31, 2017**	December 31, 2016
Equity securities	40%	**59%**	59%
Fixed income securities	45%	**41%**	41%
Other	15%	**—%**	—%
Total	100%	**100%**	100%

The following table summarizes the fair value of plan assets for the Company's pension plans recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in note 17:

($millions)	Total	Level 1	Level 2	Level 3
December 31, 2017				
Cash and cash equivalents	4	4	—	—
Equity securities	532	249	283	—
Fixed income securities	368	368	—	—
Total	904	621	283	—
December 31, 2016				
Cash and cash equivalents	3	3	—	—
Equity securities	501	242	259	—
Fixed income securities	350	350	—	—
Total	854	595	259	—

Expected Benefit Payments and Employer Contributions

($millions)	2018	2019	2020	2021	2022	2023-2027
Pension	44	45	46	48	48	254
OPEB	2	2	3	3	3	16

In 2018, the Company expects to contribute approximately $20 million and $2 million to the pension plans and OPEB plans, respectively.

Retirement Savings Plan

In addition to the retirement plans discussed above, the Company also has defined contribution employee savings plans available to eligible employees. Employees may participate in a matching contribution where the Company matches a certain percentage of before-tax employee contributions of up to 5% of eligible pay per pay period. The Company expensed pre-tax employer matching contributions of $8 million in both 2017 and 2016.

16. Asset Retirement Obligations

The Company's AROs relate to the legal obligation to disconnect, purge and cap abandoned pipelines, capping abandoned storage wells, and in some buildings, special handling and disposition of asbestos if it is disturbed.

The Company has non-asbestos AROs which include easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to the non-asbestos ARO because the fair value of the ARO cannot be reasonably estimated. The Company's pipeline system is considered a critical component of its business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term.

AROs are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

The liability for the expected cash flows as recognized in the Financial Statements reflect discount rates ranging from 4.22% to 5.50% (2016 – 4.22% to 5.50%). A reconciliation of movements in the Company's ARO is as follows:

($millions)	**December 31, 2017**	December 31, 2016
Balance, beginning of year	**417**	440
Accretion expense	**19**	20
Liabilities incurred	**5**	7
Liabilities settled	**(8)**	(7)
Revisions in estimated cash flows	**(34)**	(43)
Balance, end of year	**399**	417

17. Risk Management and Financial Instruments

The Company's earnings, cash flows and OCI are subject to movements in natural gas prices and foreign exchange rates. Portions of these risks are borne by customers through certain regulatory mechanisms. Corporate risk management policies, processes and systems have been designed by the ultimate parent, Enbridge, to mitigate these risks.

The following summarizes the types of risks to which the Company is exposed and any applicable risk management instruments used to mitigate them.

Commodity Price Risk

Fluctuations in natural gas prices affect the Company's gas purchase costs for the Company's own operating requirements as well as for the gas supply costs the Company incurs for and collect from their system customers. The Company's gas procurement policy primarily includes contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. Commodity price volatility and absolute price levels also impact the amount of natural gas used by customers. Fluctuations in natural gas prices are borne by the customer in accordance with OEB directive.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. The Company generates certain revenues denominated in U.S. dollars. As a result, the Company’s earnings and cash flows are exposed to fluctuations resulting from U.S. dollars exchange rate variability.

During the third quarter of 2017, Union Gas took assignment of a number of EGD customer storage contracts, some of which were denominated in U.S. dollars. EGD also novated, to Union Gas, cash flow hedges that were used to manage exposure to changes in currency exchange rates in the assigned storage contracts.

Derivative Instruments

At December 31, 2017, the Company had approximately $1 million related to derivative instruments used as foreign exchange cash flow hedges (2016 – $nil), included in Accounts receivable and other and Regulatory and other assets. This amount is recorded at fair value as described below.

The Company's derivative instruments relating to foreign exchange forward contracts mature through 2023 and have a notional principal of $21 million (U.S. $17 million) (2016 – $nil).

Fair Value Measurements

Financial instruments recorded at fair value on the Balance Sheets are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of the Company's financial instruments that are actively traded in the secondary market are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency. The fair value of the Company's pension plan assets designated as Level 2 financial instruments is determined through the market approach valuation technique using observable inputs including matrix pricing and market corroborated pricing. The fair value of foreign exchange contracts are also determined through the market value approach based on the extrapolation of observable future prices and rates. The fair value of other financial instruments relating to pension assets is disclosed in note 15.

Level 3 Valuation Techniques

Level 3 valuation techniques include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation. The fair value of the Company's pension plan assets designated as Level 3 financial instruments is determined through the market approach valuation technique using unobservable inputs including investment manager pricing for private placements and private equities.

There were no transfers between levels during the year ended December 31, 2017.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts that could have been realized in current markets.

	December 31, 2017		December 31, 2016	
($millions)	**Book Value**	**Fair Value**	Book Value	Fair Value
Long-term debt, including current maturities[a]	**3,815**	**4,327**	3,440	3,888

[a] Excludes unamortized items.

The fair value of the Company's Long-term debt is determined based on market-based prices as described in the Level 2 valuation technique described above.

The fair values of Cash and cash equivalents, Accounts receivable and other, Accounts payable and accrued charges, Short-term borrowings and Commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligations. The maximum exposure to credit risk for the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement cost of gas loans at December 31, 2017 is $93 million receivable (2016 – $84 million receivable). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

The Company manages its credit risk on Cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on Accounts receivable, the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2017 amounted to $43 million (2016 – $39 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

Entering into derivative financial instruments may also result in exposure to credit risk. The Company has entered into risk management transactions with institutions that possess investment grade credit ratings.

The Company continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31, 2017**	December 31, 2016
Current	**386**	275
30 Days over due	**13**	10
60 Days over due	**4**	3
90+ Days over due	**8**	6
Total trade accounts receivable	**411**	294
Allowance for doubtful accounts	**(6)**	(5)
Total trade accounts receivable, net[a]	**405**	289

[a] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

For the years ended December 31, 2017 and 2016, no one customer accounted for more than 10% of sales or 10% of receivables.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 12).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2017:

($millions)	Total	2018	2019-2020	2021-2022	Thereafter
Commercial paper	485	485	—	—	—
Accounts payable and accrued charges	730	730	—	—	—
Long-term debt (including principal and interest)	6,503	570	294	607	5,032
Total	7,718	1,785	294	607	5,032

18. Stock Based Compensation

Until the close of the Merger, the Spectra Energy Corp 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provided for the granting of stock options, restricted and unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who performed services for Spectra Energy, including certain employees of Union Gas.

Performance and phantom awards granted under the 2007 LTIP typically became 100% vested on a three-year anniversary of the grant date. Options granted under the 2007 LTIP were issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, has ten-year terms and vested ratably over a three-year term.

Upon the close of the Merger or shortly thereafter, most Performance awards under the 2007 LTIP vested except for a portion of performance awards which were converted to 0.984 of Enbridge common stock that would time-vest at the end of 2018 if employment is continued. Likewise, Phantom awards were converted to 0.984 of Enbridge common stock that will vest as originally scheduled under the 2007 LTIP if employment is continued. The 2007 LTIP ceased after the Merger and qualified Union Gas employees may participate in a long-term incentive plan under Enbridge thereafter. There was no compensation expense recognized under a new long-term incentive plan under Enbridge in 2017.

Spectra Energy (and Enbridge after the Merger) allocated to Union Gas pre-tax stock-based compensation expense included in Operating Income for 2017 and 2016 as follows, the components of which are described further below:

Performance Awards

Under the 2007 LTIP, Spectra Energy granted stock-based performance awards. The performance awards generally vested over three years at the earliest, if performance metrics were met. The then unvested and outstanding performance awards granted previously contained market conditions based on the total shareholder return of Spectra Energy common stock relative to a pre-defined peer group. The equity-classified awards with market conditions were valued using the Monte Carlo valuation method.

Pre-tax compensation expense recorded by the Company for the years ended December 31, 2017 and 2016 for Performance awards were $2 million annually. The total fair value of the Performance awards vested was U.S. $6 million in 2017 and U.S. $1 million in 2016.

Phantom Awards

Under the 2007 LTIP, Spectra Energy also granted stock-based phantom awards. The phantom awards generally vested over three years. The liability-classified awards settled in cash at vesting. The liability-classified awards were remeasured at each reporting period until settlement.

Pre-tax compensation expense recorded by the Company for the years ended December 31, 2017 and 2016 for Phantom awards were $2 million annually. The total fair value of the Phantom awards vested was U.S. $1 million in 2017 and U.S. $1 million in 2016.

19. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Balance Sheets. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company's potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

20. Changes in Working Capital

($millions)	**December 31, 2017**	December 31, 2016
GHG compliance liabilities	**238**	—
Accounts receivable	**(114)**	(126)
Inventories	**19**	40
Accounts payable and accrued charges	**75**	35
Income tax receivable	**(9)**	(5)
Accumulated other comprehensive loss	**15**	19
Other	**14**	23
Total Changes in working capital	**238**	(14)

21. Commitments and Contingencies

Commitments

The table below is a summary of the Company's commitments, not otherwise disclosed in the Financial Statements, due by period.

($millions)	**Total**	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
Operating leases	33	7	6	7	6	7	—
Purchase obligations[a]	2,407	509	260	213	165	146	1,114
Total commitments	2,440	516	266	220	171	153	1,114

[a] Includes: firm capacity payments that provide the Company with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software and consulting or advisory services; and contractual obligations for engineering, procurement and construction costs for pipeline projects. Due to a timing uncertainty, all procurement obligations have been included in 2018 as the Company is unable to reasonably estimate the payments due by period.

Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated.

In April 2016, the Ontario Ministry of the Environment and Climate Change (MOECC) issued a Director’s Order (Order) naming the Company, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of the Company in Hamilton. In May 2016, the Company appealed the Order, and in June 2016, the Environmental Review Tribunal (Tribunal), on consent of the MOECC’s Director, stayed the application of parts of the Order. The Tribunal has extended the stay of the Order several times, which has allowed the owner of the property (with the cooperation of the adjacent owners) to prepare a plan of action, including discussions with the MOECC and other neighbours (City of Hamilton and Infrastructure Ontario). The Company continues to monitor the matter, and to cooperate with the owner of the source property, the MOECC and other adjacent owners. The risk of material environmental liability is unknown at this time.

Other than the potential contingency noted above, of which the impact is unknown, the Company has no reason to believe that the ultimate outcome of these matters could have a significant impact on its Financial Statements.

Tax Matters

The Company maintains tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

DIRECTORS

Cynthia L. Hansen
Stephen W. Baker
David G. Unruh

OFFICERS

Stephen W. Baker
President

Cynthia L. Hansen
Chair and Executive Vice President, Utilities & Power Operations

Allen C. Capps
Controller

David G. Simpson
Vice President, Regulatory, Lands and Public Affairs

Tanya C. Mushynski
Vice President, Law

James G. Redford
Vice President, Business Development - Storage and Transmission

Paul Rietdyk
Vice President, Engineering, Construction and Storage and Transmission Operations

Michael G.P. Shannon
Vice President, Distribution Operations

Wendy H. Zelond
Vice President, Finance

Sarah Van Der Paelt
Vice President, In-Franchise Sales, Marketing and Customer Care

Christopher G. Tuckwell
Assistant Controller

Wanda M. Opheim
Treasurer

Maximilian G. Chan
Assistant Treasurer

Tyler W. Robinson
Vice President and Corporate Secretary

David Taniguchi
Assistant Corporate Secretary

Kelly L. Gray
Assistant Corporate Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **AST Trust Company**

Union Gas Limited Preferred shares are listed on the Toronto Stock Exchange
Class A Preferred, Series A - 5½% (UNG.PR.C)

Class A Preferred, Series B - 6% (UNG.PR.D)

REGISTERED OFFICE

50 Keil Drive North
Chatham, Ontario N7M 5M1

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Please see Exhibit I.1.8-STAFF-14 Attachment 9.xlsx on the OEB's RDS.

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Please see Exhibit I.1.8-STAFF-14 Attachment 10.xlsx on the OEB’s RDS.

Rating Report
Report Date:
April 4, 2012
Previous Report
April 25, 2011

Enbridge Gas Distribution Inc.

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The Company
Enbridge Gas Distribution Inc. (EGD) is a regulated natural gas distribution utility, serving approximately two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. EGD also distributes natural gas to approximately 15,500 customers in northern New York State through a wholly-owned subsidiary, St. Lawrence Gas Company (approximately 2% of total revenue). EGD is an indirect wholly-owned subsidiary of Enbridge Inc. (rated A (low)).

CP Limit: $700 million

Rating

Debt	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Ratings Update

DBRS has confirmed the Unsecured Debentures & Medium-Term Notes, Commercial Paper, and Cumulative & Cumulative Redeemable Convertible Preferred Share ratings of Enbridge Gas Distribution Inc. (EGD or the Company) at "A", R-1 (low) and Pfd-2 (low), respectively, all with Stable trends. The rating confirmation is based on EGD's low business risk operations, stable regulatory environment in Ontario, strong franchise area and stable financial profile.

EGD's low business risk profile is supported by a large customer base (approximately two million customers, the largest in Canada), which has allowed the Company to achieve operational efficiency and generate earnings in excess of approved return on equity (ROE) under the incentive regulation (IR) framework since 2008. The Company benefits from a stable regulatory system, having no exposure to gas price risk in Ontario, where it generates approximately 98% of its revenues. EGD's franchise area (largely in the Greater Toronto Area) is viewed as one of the most rapidly growing and economically strong service areas in Canada. Approximately 95% of the Company's earnings are contributed by relatively stable regulated distributions, transportation and storage, with the remainder contributed by unregulated storage business, which benefits from strong demand, due to its strategic locations.

EGD's financial profile remained stable in 2011, with all credit metrics being commensurate with DBRS's "A" rating guidelines. DBRS notes that the Company requires significant liquidity to finance working capital (mostly gas inventory for winter distributions). Given the low gas price environment, EGD's liquidity remains adequate to meet its operational needs. Over the medium term, moderate cash flow deficits are expected, due to a large capex program. However, EGD's current debt leverage is well below the regulatory capital structure of 36% equity, providing EGD with significant financial flexibility. DBRS expects the Company to remain prudent in funding its cash shortfalls and maintaining its credit metrics within the "A" rating category. In August 2011, the Company financed its $66 million acquisition of 15-megawatt (MW) solar power assets from its parent, Enbridge Inc., with equity, which was viewed as positive to the financial profile.

Rating Considerations

Strengths
(1) Stable regulatory framework
(2) Strong franchise area with a large customer base
(3) Reasonable balance sheet and credit metrics

Challenges
(1) Weather-related volume risk
(2) Low ROE and limited rate base growth
(3) Cash flow deficits

Financial Information

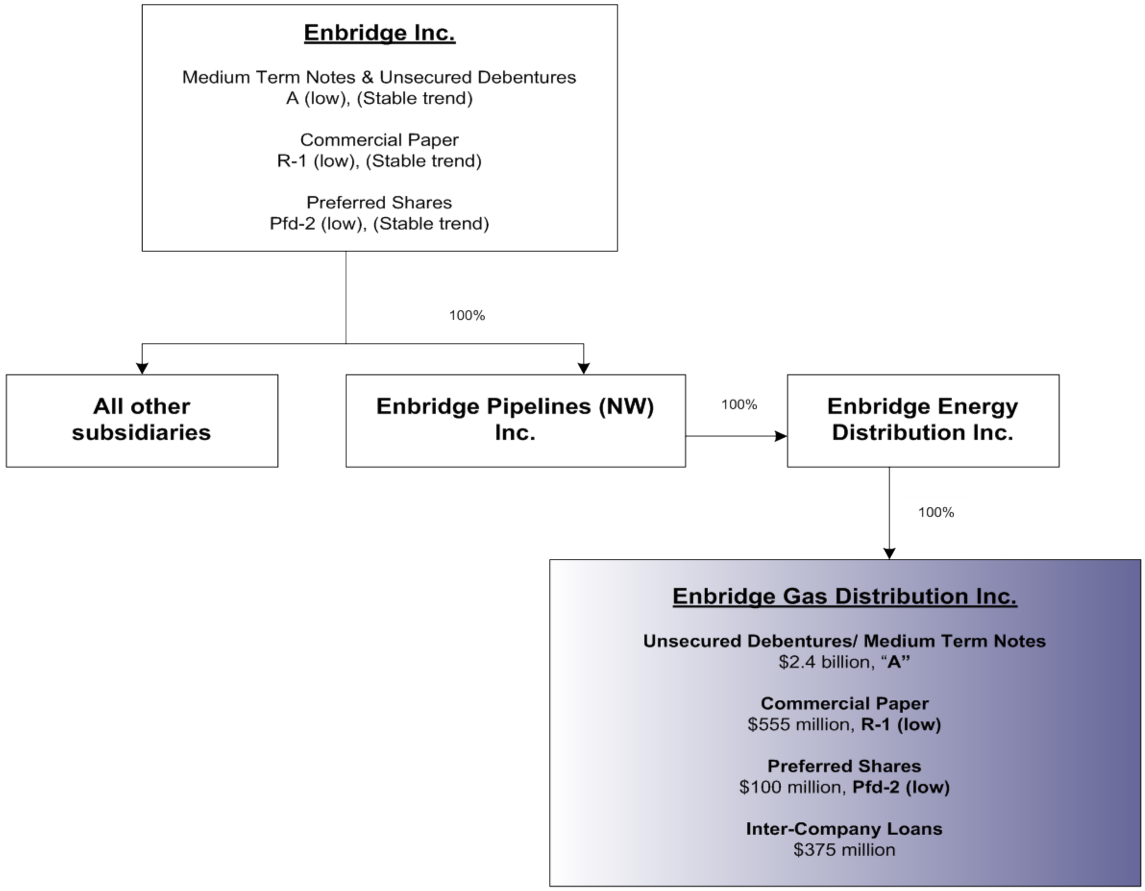
Enbridge Gas Distribution Inc.	For the year ended December 31				
($ millions)	**2011**	**2010**	**2009**	**2008**	**2007**
Net income before extra. Items	211	193	221	211	190
Cash flow from operations	497	467	504	483	423
Total debt in capital structure (1)	56.4%	55.4%	54.1%	59.3%	57.1%
EBIT gross interest coverage (times) (1)	2.69	2.62	2.87	2.55	2.62
Cash flow/Total debt (1)	19.4%	19.5%	21.7%	17.1%	16.8%
Total debt/EBITDA (times) (1)	3.85	3.59	3.32	4.12	3.90
Approved ROE	8.39%	8.39%	8.39%	8.39%	8.39%

(1) Excludes inter-company loans and/or inter-company prefered dividend income and interest expense.

Enbridge Gas Distribution Inc.

Report Date:
April 4, 2012

Simplified Organizational Chart



Rating Considerations Details

Strengths

(1) Low business risk, stable regulatory framework. EGD's low risk business is viewed as low, underpinned by its gas distribution operations and a stable regulatory environment. Gas supply costs are adjusted quarterly and are passed through to customers. Currently, the Company operates under a long-term incentive regulation (IR) framework until 2013, which provides incentives for improved efficiency and long-term regulatory stability.

(2) Strong franchise, large customer base. EGD is the largest regulated natural gas distributor in Canada, serving approximately two million customers in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong. The size of the customer base allows the Company to achieve operational efficiency. EGD has generated returns on approved equity levels in excess of 100 basis points of approved ROE over the past four years.

(3) Reasonable balance sheet and credit metrics. EGD maintains a reasonable balance sheet and strong credit metrics commensurate with the current ratings. EGD is committed to maintaining its capital structure within the regulatory approved level of 64% debt/36% equity. The current debt leverage (56%) provides the Company with significant financial flexibility.

Challenges

(1) Volume risk due to weather. Weather remains the most significant risk, as forecast volumes – based on the normalized weather – are built into the Company's base rates, while actual usage varies with weather. Therefore, colder weather than normal in the forecast generally results in higher earnings compared to periods of warmer than normal weather.

(2) Limited rate base growing and low ROE during the IR period. Until the next cost-of-service (COS) application expected in 2013, the rate base growth will be limited and the relatively low current approved ROE of 8.39% will not be changed.

(3) Free cash flow deficits. Free cash flow deficits almost doubled in 2011 to $198 million as a consequence of increased dividend and growing capex. Negative free cash flow is expected to continue in 2012, since Capex is expected to remain high. While incremental cash flow is also expected to come from power solar assets (Amhersburg Solar Projects (15 MW), which were acquired from Enbridge Inc. in August 2011 for $66 million), cash contributions from these power projects will be very modest.

Enbridge Gas Distribution Inc.

Report Date:
April 4, 2012

Earnings and Outlook

($ millions CAD) For the 12 months ended December 31	2011	2010	2009	2008	2007
Net gas distribution revenue	669	605	576	506	485
Gas transportation service revenue	352	390	449	505	500
Gas distribution margin	1,021	995	1,025	1,011	985
Other revenue	104	108	108	94	81
Total revenue	1,125	1,103	1,133	1,105	1,066
EBITDA	665	666	699	684	644
EBIT	384	396	445	445	416
Earnings sharing	13	19	19	6	0
Intercompany dividend income	63	63	63	63	63
Interest expense (external)	(143)	(151)	(155)	(175)	(159)
Interest expense (intercompany)	(27)	(27)	(27)	(27)	(27)
Net income before extra. Items	211	193	221	211	190
Extra items	0	0	0	0	0
Reported net income	211	193	221	211	190
Deemed equity (EGD)	36%	36%	36%	36%	36%
Approved ROE (EGD)	8.39%	8.39%	8.39%	8.39%	8.39%
Actual ROE	10.79%	9.91%	11.32%	11.06%	10.58%

Summary

- The Company's earnings are contributed mainly by gas distribution operations (59% of 2011 net revenue) and gas transportation operations (31% of net revenue), with the remaining contributed by the storage business.
- Most earnings from gas distribution operations are generated by EGD, with a small portion (about 2% of revenues) contributed by its wholly-owned St. Lawrence, a natural gas distributor in New York State.
- The storage business includes regulated and unregulated facilities, with the latter accounting for approximately 5% of overall earnings (DBRS estimates).
- Earnings in regulated operations are mainly driven by rate base growth and approved ROE (both of which remained stable in 2011), as well as weather, which in 2011 was colder than 2010 and was largely responsible for a slight increase in earnings.
- In addition to colder weather, modest customer growth and higher distribution charges also contributed to the increase.
- DBRS notes that transportation revenue have declined since 2007, due to a gradual decrease in volumes.
- Earnings sharing represents EGD's 50% share of the actual return on the approved equity level (excluding the effect of weather), in excess of 100 basis points above the allowed ROE.
- Dividend income represents the cash income from EGD's $825 million investment in its affiliate (IPL System Inc.), the holder of the Company's $375 million intercompany loan outstanding at December 31, 2011. The interest expense on this loan was $27 million in 2011.

Outlook

- The Company's earnings, under normal weather conditions, should increase moderately in 2012, driven primarily by customer growth in the Company's franchise areas.
- The rate base and ROE are not expected to change until 2013, the rebasing year for EGD.
- The Company expects to add between 35,000 and 40,000 customers annually throughout the IR period.
- Earnings growth is also expected to come from power solar assets (Amhersburg Solar Projects (15 MW), which were acquired from Enbridge Inc. in August 2011 for $66 million). However, the earnings contribution from these power projects will be very modest.

DBRS

Enbridge Gas Distribution Inc.

Report Date:
April 4, 2012

Financial Profile

Consolidated Cash Flow Statement: EGD	For the year ended December 31				
($ millions CAD)	**2011**	**2010**	**2009**	**2008**	**2007**
Net income before extra. items	211	193	221	211	190
Depreciation & amortization	281	270	254	239	228
Deferred income taxes/Other	5	4	29	33	5
Cash flow from operations	497	467	504	483	423
Dividends paid	(220)	(210)	(185)	(163)	(70)
Capex	(475)	(365)	(370)	(411)	(385)
Free cash flow before WC	(198)	(108)	(51)	(91)	(32)
Changes in working capital (WC)	17	45	467	(115)	136
Net free cash flow	(181)	(63)	416	(207)	103
Acquisitions (*)	0	0	0	0	0
Assets sales/Divestitures	0	0	0	0	0
Net changes in equity (*)	0	0	0	0	88
Net changes in debt	174	69	(469)	261	(167)
Other	3	(13)	(15)	6	(14)
Change in cash	(4)	(7)	(68)	60	10
Total external debt ($ millions)	2,562	2,391	2,318	2,818	2,514
Inter-company debt ($ millions)	375	375	375	375	375
Total debt/Capital (1)	56.4%	55.4%	54.1%	59.3%	57.1%
EBIT interest coverage (times) (1)	2.69	2.62	2.87	2.55	2.62
Cash flow/Total debt (1)	19.4%	19.5%	21.7%	17.1%	16.8%
Dividends/Cash flow	43.9%	44.5%	35.9%	32.7%	15.4%

(1) Excludes inter-company loans and/or inter-company dividend income and interest expense.

(*) In August 2011, EGD issued $66 million to finance its $66 million solar asset acquisition from Enbridge Inc.

Summary

- Higher earnings and depreciation contributed to increased cash flow from operations. However, in 2011 free cash flow deficits almost doubled to $198 million as a result of increased dividends and large capex.
- Higher capex in 2011 was mainly due to its customer care system and unregulated storage expansion.
- EGD has a targeted dividend payment of 90% to 100%, subject to maintaining a capital structure in line with regulatory levels.
- As a result, even the Company financed cash deficits with debt, though its capital structure remained stable (compared to 2010) and was well within the regulatory capital structure of 36% equity.
- Other key credit metrics: EBIT-interest coverage and cash flow-to-debt ratio remained stable and were in line with the "A" rating category.
- The Company issued $66 million in equity to finance its $66 million acquisition of solar assets from Enbridge Inc. However, due to the nature of inter-company transaction, the issuance of equity did not record in the cash flow statement in 2011, though the equity base increased by $66 million.

Outlook

- Capex for 2012 is expected to be approximately $440 million on capital projects and maintenance. Capital projects largely include the iron cast replacement program, construction of the technical training program and power generation.
- As a result, the Company is expected to generate free cash flow deficits of approximately $160 million in 2012. DBRS expects EGD to remain prudent in its financing of the cash shortfalls in order to maintain its balance sheet leverage within "A" rating guidelines.

Long-Term Debt Maturities and Liquidity

Bank Lines/Liquidity

Credit Facilities			As at Dec. 31, 2010
	Total Facilites	**Credit Facilities Draws**	**Available**
Committed lines of credit	700	545	155
Uncommitted lines of credit*	12	10	2
Total	712	555	157

* The uncommitted lines of credit are at St. Lawrence Gas, Inc.

- EGD requires relatively high liquidity to support its volatile and highly seasonal working capital needs and increased capital expenditures.
- Working capital requirements are very seasonal and heavily influenced by the volatility of gas prices.
- EGD has a $700 million CP program, of which $155 million was available at the end of 2011. The CP program is fully backed by a $700 million, 364-day revolving committed credit facility.
- DBRS views EGD's current liquidity as adequate. Nevertheless, a combination of cold weather and high gas prices could exhaust the Company's available liquidity. However, this scenario is unlikely, given the current low gas price environment.

Debt	As at Dec. 31, 2011 (CAD millions)
Commercial paper	555
Bank overdraft	7
Debentures	85
Medium-term notes	2,295
Total	**2,942**
Other and Deferred debt issue costs	(5)
Total Debt	**2,937**

Long-Term Debt Maturity schedule	Less than 1 year	1-3 years	3-5 years	Thereafter	Total
As at Dec. 31, 2011 (CAD millions)	-	400	-	1,974	2,374

- Refinancing the debt is still manageable, despite $400 million of debt due in the coming three years.
- In April 2011, EGD repaid its $150 million of 10.80% debentures. The Company then issued $100 million medium term notes (MTNs) at 4.95%, as well as additional draws on its credit facilities at lower interest rates. The company took the opportunity of a low interest rate environment to refinance, lowering interest expense for future years.
- EGD is subject to an EBIT interest covenant of two times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
- The covenant does not apply to debt issuance for refinancing.
- The Company was in compliance with the test at fiscal year-end 2011.

Inter-company debt

- As of December 31, 2011, EGD owned $825 million of Class D, non-voting redeemable, retractable preferred shares of IPL System Inc. (IPL), which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans, which is deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company.

Regulation

Regulatory Overview

The Ontario Energy Board (OEB) regulates EGD's gas storage, transmission and distribution businesses. Consumers in Ontario have been able to choose their natural gas supplier since 1985. The gas purchase cost is passed on to customers through quarterly adjustments; as a result, the Company's distribution margin is not impacted by the gas purchase cost.

Gas Distribution: Ontario

- In 2008, the Company moved to an IR methodology, with 2007 as the base year for a five-year term from 2008 to 2012. EGD can request a consultation in year four to consider an extension of the plan, to a maximum of an additional two years.
- Revenue escalation adjusts distribution revenues every year (50% of inflation in 2011 and 45% inflation in 2012), relying on an annual process to forecast volume and customer additions.
- The Company is allowed to have several costs and deferred accounts outside of revenue escalation formulae, including capex invested in new power generation and expenses above a defined threshold.
- The Company's 2011 ROE of 8.39% and deemed equity of 36% will remain unchanged until 2013.
- EGD will retain earnings in excess of the approved ROE up to a 100-basis point and will share equally with customers the actual return on the approved equity level (excluding the effects of weather) in excess of 100 basis points above the approved ROE.
- In September 2011, EGD filed an application with the OEB to adjust rates for 2012 pursuant to the approved IR formula. The OEB approved $1,004 million for 2012, or 98% of the requested amount. The rate adjustment was effective January 1, 2012.
- A hearing with respect to the remaining amount of $20 million (or 2%) was held by the OEB in January 2012, with a decision expected by April 2012.

Gas Distribution: New York

- The Company owns St. Lawrence Gas Company (SLG), which provides natural gas distribution services to 15,500 customers in New York State.
- The regulatory framework in New York is under cost of service and is viewed as stable. The approved ROE for 2011 was 10.5% on a deemed equity of 50%. Any earnings above 11% will be shared equally with customers. SLG had no earnings sharing in 2011 and 2010.
- Gas supply costs are adjusted annually.

Gas Storage

- EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates. Revenues from the unregulated storage business have increased since the OEB's change of EGD's pricing policy in 2007.

Enbridge Gas Distribution Inc.

Report Date:
April 4, 2012

Enbridge Gas Distribution Inc.

Balance Sheet ($ millions CAD)	Dec. 31	Dec. 31	Dec. 31		Dec. 31	Dec. 31	Dec. 31
Assets	**2011**	**2010**	**2009**	**Liabilities & Equity**	**2011**	**2010**	**2009**
Cash & equivalents	9	13	0	S.T. borrowings	563	349	1,036
Accounts receivable	402	457	439	Current portion L.T.D.	0	150	150
Inventories	380	400	396	Accounts payable	67	57	25
Others	261	345	362	Deferred tax	2	5	5
				Others	646	793	756
Total Current Assets	**1,052**	**1,215**	**1,197**	**Total Current Liabilities**	**1,278**	**1,354**	**1,972**
Net fixed assets	4,770	4,458	4,290	Long-term debt (L.T.D.)	2,374	2,267	1,507
Future income tax assets	0	0	0	Deferred income taxes	178	171	185
Goodwill & intangibles	179	167	179	Other L.T. liabilities	1,502	1,433	1,347
Investments & others	1,314	1,312	1,312	Shareholders equity	1,983	1,927	1,967
Total Assets	**7,315**	**7,152**	**6,978**	**Total Liab. & SE**	**7,315**	**7,152**	**6,978**

Liquidity & Capital Ratios	**2011**	**2010**	**2009**	**2008**	**2007**
Current ratio (times)	0.82	0.90	0.61	0.66	0.98
Total debt in capital structure	59.7%	58.9%	57.8%	62.2%	60.5%
Cash flow/Total debt	16.9%	16.9%	18.7%	15.1%	14.6%
Cash flow/Capex (times)	1.05	1.28	1.36	1.17	1.10
(Cash flow - Dividends)/Capex (times)	0.58	0.70	0.86	0.78	0.92
Dividend payout ratio	104.3%	108.8%	83.7%	77.2%	36.9%
Dividends/Cash flow	43.9%	44.5%	35.9%	32.7%	15.4%
Profitability Ratios					
EBITDA margin	27.0%	26.9%	24.1%	22.0%	21.8%
EBIT margin	15.6%	16.0%	15.3%	14.3%	14.1%
Profit margin	8.6%	7.8%	7.6%	6.8%	6.4%
Return on equity	10.8%	9.9%	11.3%	11.1%	10.6%
Return on capital	6.4%	6.3%	6.6%	6.5%	6.0%
Allowed ROE (EGD)	8.39%	8.39%	8.39%	8.39%	8.39%
Allowed ROE (St. Lawrence)	10.5%	10.5%	-	-	-
Excluding Inter-company Debt, Inter-company Dividend Income and Interest Expense					
Cash flow/Debt	19.4%	19.5%	21.7%	17.1%	16.8%
Total debt/Capital	56.4%	55.4%	54.1%	59.3%	57.1%
EBITDA gross interest coverage (times)	4.65	4.41	4.51	3.92	4.06
EBIT gross interest coverage (times)	2.69	2.62	2.87	2.55	2.62
Debt/EBITDA (times)	3.85	3.59	3.32	4.12	3.90

Enbridge Gas Distribution Inc.

Report Date:
April 4, 2012

Rating

Debt Rated	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating History

Debt Rated	Current	2011	2010	2009	2008	2007
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A	A
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

Notes:
All figures are in Canadian dollars unless otherwise noted.

Rating Report
Report Date:
June 28, 2012
Previous Report
April 4, 2012

Insight beyond the rating.

Enbridge Gas Distribution Inc.

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The Company
Enbridge Gas Distribution Inc. (EGD) is a regulated natural gas distribution utility, serving approximately two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. EGD also distributes natural gas to approximately 15,500 customers in northern New York State through a wholly-owned subsidiary, St. Lawrence Gas Company (approximately 2% of total revenue). EGD is an indirect wholly owned subsidiary of Enbridge Inc. (rated A (low)).

Commercial Paper Limit:
$700 million

Rating

Debt	Rating	Trend
Commercial Paper	R-1 (low)	Stable
Unsecured Debentures & Medium-Term Notes	A	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Stable

Ratings Update

The credit profile of Enbridge Gas Distribution Inc. (EGD or the Company) has remained stable in Q1 2012, based on the latest financial results and regulatory development. The Company's rating is based on its low business risk operations, stable regulatory environment in Ontario, strong franchise area and stable financial profile.

EGD's low business risk profile is supported by a large customer base (approximately two million customers, the largest in Canada), which has allowed the Company to achieve operational efficiency and generate earnings in excess of approved return on equity (ROE) under the incentive regulation (IR) framework since 2008. The Company benefits from a stable regulatory system, having no exposure to gas price risk in Ontario, where it generates approximately 98% of its revenues. EGD's franchise area (largely in the Greater Toronto Area) is viewed as one of the most rapidly growing and economically strong service areas in Canada. Approximately 95% of the Company's earnings are contributed by relatively stable regulated distributions, transportation and storage, with the remainder contributed by unregulated storage business, which benefits from strong demand, due to its strategic locations. EGD will be under the cost-of-service (COS) year in 2013, which is expected to provide it an opportunity to obtain a larger rate base, higher allowed ROE (currently 8.39%) and higher deemed equity (currently 36%).

EGD's financial profile continued to remain stable in Q1 2012, with all credit metrics being commensurate with DBRS's "A" rating guidelines. DBRS notes that the Company requires significant liquidity to finance working capital (mostly gas inventory for winter distributions). Given the low gas price environment, EGD's liquidity remains adequate to meet its operational needs. Over the medium term, moderate cash flow deficits are expected, due to a large capex program. However, EGD's current debt leverage is well below the regulatory capital structure of 64% debt/36% equity, providing EGD with significant financial flexibility. DBRS expects the Company to remain prudent in funding its cash shortfalls and maintaining its credit metrics within the "A" rating category.

Rating Considerations

Strengths
(1) Stable regulatory framework
(2) Strong franchise area with a large customer base
(3) Reasonable balance sheet and credit metrics

Challenges
(1) Weather-related volume risk
(2) Low ROE and limited rate base growth
(3) Cash flow deficits

Financial Information

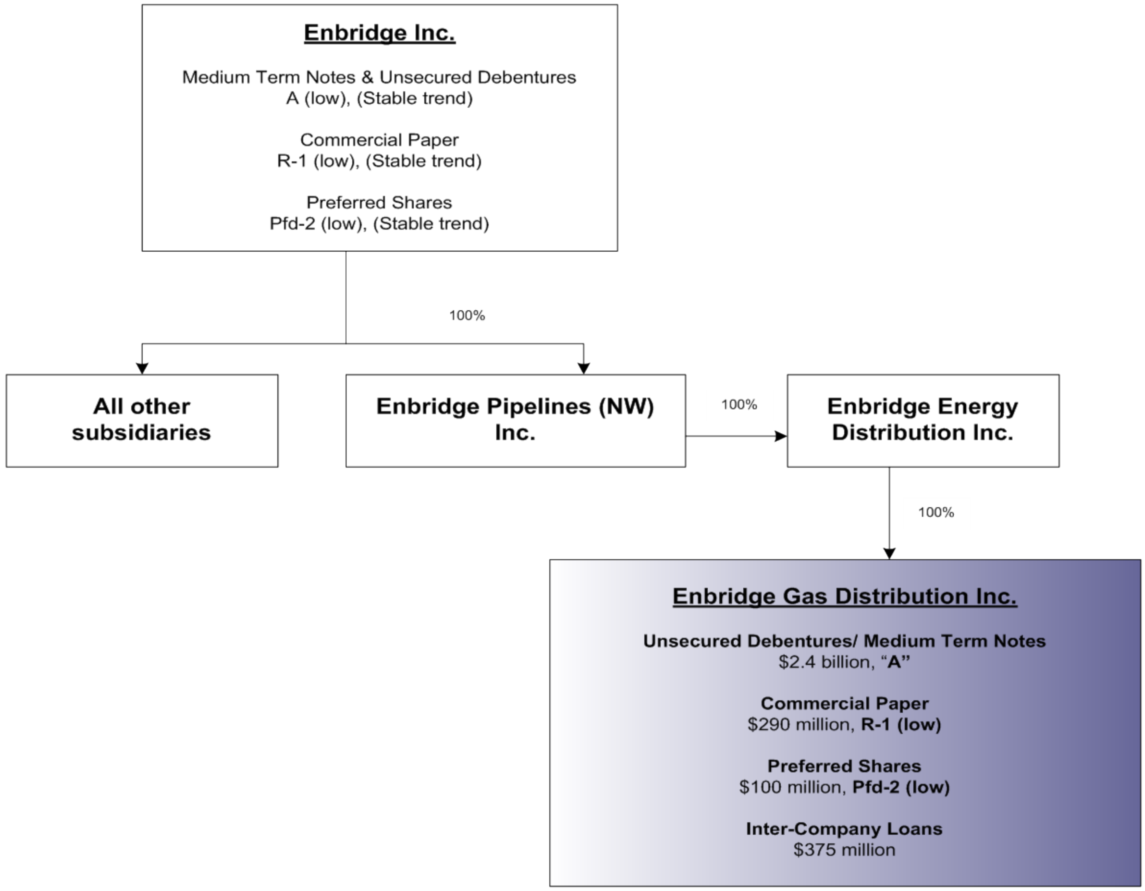
	USGAAP	USGAAP	MIX	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Enbridge Gas Distribution Inc.	**3 mos. Mar 31**		**12 mos. Mar. 31**		**For the year ended December 31**			
(CA$ millions)	**2012**	**2011**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**
Net income before extra. Items	73	104	180	211	193	221	211	190
Cash flow from operations	153	176	474	497	467	504	483	423
Total debt in capital structure (1)	49.2%	52.0%	49.2%	56.4%	55.4%	54.1%	59.3%	57.1%
EBIT gross interest coverage (times) (1)	2.95	3.78	2.40	2.69	2.62	2.87	2.55	2.62
Cash flow/Total debt (1)	26.4%	32.8%	20.4%	19.4%	19.5%	21.7%	17.1%	16.8%
Total debt/EBITDA (times) (1)	2.86	2.16	3.75	3.85	3.59	3.32	4.12	3.90
Approved ROE	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%

(1) Excludes inter-company loans and/or inter-company prefered dividend income and interest expense.

Enbridge Gas Distribution Inc.

Report Date:
June 28, 2012

Simplified Organizational Chart (1)



(1) Debt information as of March 31, 2012.

Rating Considerations Details

Strengths
(1) **Low business risk, stable regulatory framework.** EGD's low risk business is underpinned by its gas distribution operations and a stable regulatory environment. Gas supply costs are adjusted quarterly and are passed through to customers. Currently, the Company operates under a long-term IR framework until 2013, which provides incentives for improved efficiency and long-term regulatory stability.

(2) **Strong franchise, large customer base.** EGD is the largest regulated natural gas distributor in Canada, serving approximately two million customers in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong. The size of the customer base allows the Company to achieve operational efficiency. EGD has generated returns on approved equity levels in excess of 100 basis points of approved ROE over the past four years.

(3) **Reasonable balance sheet and credit metrics.** EGD maintains a reasonable balance sheet and strong credit metrics commensurate with the current ratings. EGD is committed to maintaining its capital structure within the regulatory approved level of 64% debt/36% equity. The current debt leverage (56%) provides the Company with significant financial flexibility.

Challenges
(1) **Volume risk due to weather.** Weather remains the most significant risk, as forecast volumes – based on the normalized weather – are built into the Company's base rates, while actual usage varies with actual weather. Therefore, colder weather than normalized weather in the forecast generally results in higher earnings compared to periods of warmer than normalized weather.

(2) **Limited rate base growth and low ROE during the IR period.** Until the next COS application expected in 2013, the rate base growth will be limited and the relatively low current approved ROE of 8.39% will not be changed.

(3) **Free cash flow deficits.** Free cash flow deficits almost doubled in 2011 to $198 million as a consequence of increased dividend and growing capex. Negative free cash flow is expected to continue in 2012, since capex is expected to remain high. While incremental cash flow is also expected to come from power solar assets (Amhersburg Solar Projects (15 MW), which were acquired from Enbridge Inc. in August 2011 for $66 million), cash contributions from these power projects will be very modest.

Earnings and Outlook

(CA$ millions)	USGAAP 3 mos. Mar 31 2012	USGAAP 3 mos. Mar 31 2011	MIX 12 mos. Mar. 31 2012	CGAAP 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
Net gas distribution revenue	198	193	674	669	605	576	506	485
Gas transportation service revenue	93	140	305	352	390	449	505	500
Gas distribution margin	291	333	979	1,021	995	1,025	1,011	985
Other revenue	29	28	105	104	108	108	94	81
Total revenue	320	361	1,084	1,125	1,103	1,133	1,105	1,066
EBITDA	203	249	619	665	666	699	684	644
EBIT	124	174	334	384	396	445	445	416
Earnings sharing	6	6	13	13	19	19	6	0
Intercompany dividend income	0	0	0	(27)	(27)	(27)	(27)	(27)
Interest expense (external)	(42)	(46)	(139)	(143)	(151)	(155)	(175)	(159)
Interest expense (intercompany)	16	16	63	63	63	63	63	63
Net income before extra. Items	73	104	180	211	193	221	211	190
Extra items	0	0	0	0	0	0	0	0
Reported net income	73	104	180	211	193	221	211	190
Deemed equity (EGD)	36%	36%	36%	36%	36%	36%	36%	36%
Approved ROE (EGD)	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%
Actual ROE	13.50%	21.08%	8.22%	10.79%	9.91%	11.32%	11.06%	10.58%

Note: CGAAP columns are for the year ended December 31.

Summary

- The Company's earnings are contributed mainly by gas distribution operations (approximately 59% of 2011 net revenue) and gas transportation operations (31% of net revenue), with the remaining contributed by the storage business.
- Most earnings from gas distribution operations are generated by EGD, with a small portion (about 2% of revenues) contributed by its wholly-owned St. Lawrence, a natural gas distributor in New York State.
- The storage business includes regulated and unregulated facilities, with the latter accounting for approximately 5% of overall earnings (DBRS estimates).
- Earnings in regulated operations are mainly driven by rate base growth and approved ROE (both of which remained stable in 2011), as well as weather, which in 2011 was colder than 2010 and was largely responsible for a slight increase in earnings.
- DBRS notes that transportation revenue has declined since 2007, due to a gradual decrease in volumes.
- Earnings sharing represents EGD's 50% share of the actual return on the approved equity level (excluding the effect of weather), in excess of 100 basis points above the allowed ROE.
- Dividend income represents the cash income from EGD's $825 million investment in its affiliate (IPL System Inc.), the holder of the Company's $375 million inter-company loan outstanding at December 31, 2011. The interest expense on this loan was $27 million in 2011.

Outlook

- The Company's earnings, under normal weather conditions, should increase moderately in 2012, driven primarily by customer growth in the Company's franchise areas.
- The rate base and ROE are not expected to change until 2013, the rebasing year for EGD.
- The Company expects to add between 35,000 and 40,000 customers annually throughout the IR period.
- Earnings growth is also expected to come from power solar assets (Amhersburg Solar Projects (15 MW), which were acquired from Enbridge Inc. in August 2011 for $66 million). However, the earnings contribution from these power projects will be very modest.

Enbridge Gas Distribution Inc.

Report Date:
June 28, 2012

Financial Profile

Consolidated Cash Flow Statement: EGD (CA$ millions)	USGAAP 3 mos. Mar 31 2012	USGAAP 3 mos. Mar 31 2011	MIX 12 mos. Mar. 31 2012	CGAAP 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
Net income before extra. items	73	104	180	211	193	221	211	190
Depreciation & amortization	79	75	285	281	270	254	239	228
Deferred income taxes/Other	1	(3)	9	5	4	29	33	5
Cash flow from operations	153	176	474	497	467	504	483	423
Dividends paid	(56)	(55)	(221)	(220)	(210)	(185)	(163)	(70)
Capex	(88)	(64)	(499)	(475)	(365)	(370)	(411)	(385)
Free cash flow before WC	9	57	(246)	(198)	(108)	(51)	(91)	(32)
Changes in working capital (WC)	274	263	28	17	45	467	(115)	136
Net free cash flow	283	320	(218)	(181)	(63)	416	(207)	103
Acquisitions (2)	0	0	0	0	0	0	0	0
Assets sales/Divestitures	0	0	0	0	0	0	0	0
Net changes in equity (2)	0	0	0	0	0	0	0	88
Net changes in debt	(266)	(227)	135	174	69	(469)	261	(167)
Other	(5)	(35)	33	3	(13)	(15)	6	(14)
Change in cash	12	58	(50)	(4)	(7)	(68)	60	10
Total external debt ($ millions)	2,319	2,148	2,319	2,562	2,391	2,318	2,818	2,514
Inter-company debt ($ millions)	375	375	375	375	375	375	375	375
Total debt/Capital (1)	49.2%	52.0%	49.2%	56.4%	55.4%	54.1%	59.3%	57.1%
EBIT interest coverage (times) (1)	2.95	3.78	2.40	2.69	2.62	2.87	2.55	2.62
Cash flow/Total debt (1)	26.4%	32.8%	20.4%	19.4%	19.5%	21.7%	17.1%	16.8%
Dividends/Cash flow	35.9%	30.7%	46.2%	43.9%	44.5%	35.9%	32.7%	15.4%

(1) Excludes inter-company loans and/or inter-company dividend income and interest expense.
(2) In August 2011, EGD issued $66 million to finance its $66 million solar asset acquisition from Enbridge Inc.

Summary

- Higher earnings and higher depreciation contributed to increased cash flow from operations. However, in 2011, free cash flow deficits increased as a result of increased dividends and large capex.
- Higher capex in 2011 was mainly due to its customer care system and unregulated storage expansion.
- EGD has a targeted dividend payment of 90% to 100%, subject to maintaining a capital structure in-line with regulatory levels.
- Despite debt financing, the Company's capital structure remained stable and was well within the regulatory capital structure of 36% equity.
- Other key credit metrics: EBIT-interest coverage and cash flow-to-debt ratio remained stable and were in line with the "A" rating category.
- The Company issued $66 million in equity to finance its $66 million acquisition of solar assets from Enbridge Inc. However, due to the nature of inter-company transaction, the issuance of equity did not record in the cash flow statement in 2011, though the equity base increased by $66 million.

Outlook

- Capex for 2012 is expected to be approximately $440 million on capital projects and maintenance. Capital projects largely include the iron cast replacement program, construction of the technical training program and power generation.
- As a result, the Company is expected to generate free cash flow deficits of approximately $160 million in 2012. DBRS expects EGD to remain prudent in its financing of the cash shortfalls in order to maintain its balance sheet leverage within "A" rating guidelines.

Long-Term Debt Maturities and Liquidity

Bank Lines/Liquidity

Credit Facilities			As at Mar. 31, 2012
	Total Facilities	Drawn	Available
Committed lines of credit	700	280	420
Uncommitted lines of credit*	12	9	3
Total	712	289	423

* The uncommitted lines of credit are at St. Lawrence Gas, Inc.

- EGD requires relatively high liquidity to support its volatile and highly seasonal working capital needs and increased capex.
- Working capital requirements are very seasonal and heavily influenced by the volatility of gas prices.
- EGD has a $700 million CP program, of which $420 million was available at the end of March 2012. The CP program is fully backed by a $700 million, 364-day revolving committed credit facility.
- DBRS views EGD's current liquidity as adequate. Nevertheless, a combination of cold weather and high gas prices could exhaust the Company's available liquidity. However, this scenario is unlikely, given the current low gas price environment.

Debt	As at Mar. 31, 2012 (CAD millions)
Commercial paper	280
Other ST borowings	27
LT debt	2,387
Total	**2,694**

Long-Term Debt Maturity schedule	<1 year	1-3 years	3-5 years	Thereafter	Total
As at Dec. 31, 2011 (CAD millions)	-	400	-	1,974	2,374

- Refinancing the debt is still manageable, despite $400 million of debt due in the coming three years.
- In April 2011, EGD repaid its $150 million of 10.80% debentures. The Company then issued $100 million medium-term notes at 4.95%, as well as additional draws on its credit facilities at lower interest rates. The company took the opportunity of a low interest rate environment to refinance, lowering interest expense for future years.
- EGD is subject to an EBIT interest covenant of two times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
- The covenant does not apply to debt issuance for refinancing.
- The Company was in compliance with the test at fiscal year-end 2011 and Q1 2012.

Inter-company debt

- As of March 31, 2012, EGD owned $825 million of Class D, non-voting redeemable, retractable preferred shares of IPL System Inc. (IPL), which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans, which is deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company.

Regulation

Regulatory Overview
The Ontario Energy Board (OEB) regulates EGD's gas storage, transmission and distribution businesses. Consumers in Ontario have been able to choose their natural gas supplier since 1985. The gas purchase cost is passed on to customers through quarterly adjustments; as a result, the Company's distribution margin is not impacted by the gas purchase cost.

Gas Distribution: Ontario
- In 2008, the Company moved to an IR methodology, with 2007 as the base year for a five-year term from 2008 to 2012. EGD can request a consultation in year four to consider an extension of the plan, to a maximum of an additional two years.
- Revenue escalation adjusts distribution revenues every year (50% of inflation in 2011 and 45% inflation in 2012), relying on an annual process to forecast volume and customer additions.
- The Company is allowed to have several costs and deferred accounts outside of revenue escalation formulae, including capex invested in new power generation and expenses above a defined threshold.
- The Company's 2011 ROE of 8.39% and deemed equity of 36% will remain unchanged until 2013.
- EGD will retain earnings in excess of the approved ROE up to 100 basis points and will share equally with customers the actual return on the approved equity level (excluding the effects of weather) in excess of 100 basis points above the approved ROE.
- In September 2011, EGD filed an application with the OEB to adjust rates for 2012 pursuant to the approved IR formula. The OEB approved $1,004 million for 2012, or 98% of the requested amount. The rate adjustment was effective January 1, 2012.
- A hearing with respect to the remaining amount of $20 million (or 2%) was held by the OEB in January 2012, with a decision expected by April 2012.
- In January 2012, the Company filed a COS application for 2013, requesting distribution revenue of $1,102 million. A decision on this application is expected later in 2012.

Gas Distribution: New York
- The Company owns St. Lawrence Gas Company (SLG), which provides natural gas distribution services to 15,500 customers in New York State.
- The regulatory framework in New York is under cost of service and is viewed as stable. The approved ROE for 2011 was 10.5% on a deemed equity of 50%. Any earnings above 11% will be shared equally with customers. SLG had no earnings sharing in 2011 and 2010.
- Gas supply costs are adjusted annually.

Gas Storage
- EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates. Revenues from the unregulated storage business have increased since the OEB's change of EGD's pricing policy in 2007.

DBRS

Enbridge Gas Distribution Inc.

Report Date:
June 28, 2012

Enbridge Gas Distribution Inc.

Balance Sheet (CA$ millions)	USGAAP Mar. 31 2012	CGAAP Dec. 31 2011	CGAAP Dec. 31 2010		USGAAP Mar. 31 2012	CGAAP Dec. 31 2011	CGAAP Dec. 31 2010
Assets				**Liabilities & Equity**			
Cash & equivalents	21	9	13	S.T. borrowings	307	563	349
Accounts receivable	531	402	457	Current portion L.T.D.	0	0	150
Inventories	125	380	400	Accounts payable	579	67	57
Others	0	261	345	Deferred tax	2	2	5
				Others	0	646	793
Total Current Assets	**677**	**1,052**	**1,215**	**Total Current Liabilities**	**888**	**1,278**	**1,354**
Net fixed assets	5,418	4,770	4,458	Long-term debt (L.T.D.)	2,387	2,374	2,267
Future income tax assets	0	0	0	Deferred income taxes	312	178	171
Goodwill & intangibles	179	179	167	Other L.T. liabilities	1,416	1,502	1,433
Investments & others	1,127	1,314	1,312	Preferred shares	100	100	100
				Shareholders equity	2,298	1,883	1,827
Total Assets	**7,401**	**7,315**	**7,152**	**Total Liab. & SE**	**7,401**	**7,315**	**7,152**

Balance Sheet & Liquidity & Capital Ratios	USGAAP 3 mos. Mar 31 2012	USGAAP 3 mos. Mar 31 2011	MIX 12 mos. Mar. 31 2012	CGAAP 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
				For the year ended December 31				
Current ratio (times)	0.76	0.92	0.76	0.82	0.90	0.61	0.66	0.98
Total debt in capital structure	52.9%	56.0%	52.9%	59.7%	58.9%	57.8%	62.2%	60.5%
Cash flow/Total debt	5.7%	7.0%	17.6%	16.9%	16.9%	18.7%	15.1%	14.6%
Cash flow/Capex (times)	1.74	2.75	0.95	1.05	1.28	1.36	1.17	1.10
(Cash flow - Dividends)/Capex (times)	1.10	1.89	0.51	0.58	0.70	0.86	0.78	0.92
Dividend payout ratio	76.7%	52.9%	122.8%	104.3%	108.8%	83.7%	77.2%	36.9%
Dividends/Cash flow	35.9%	30.7%	46.2%	43.9%	44.5%	35.9%	32.7%	15.4%
Profitability Ratios								
EBITDA margin	23.3%	27.4%	25.5%	27.0%	26.9%	24.1%	22.0%	21.8%
EBIT margin	14.2%	19.1%	13.8%	15.6%	16.0%	15.3%	14.3%	14.1%
Profit margin	8.4%	11.4%	7.4%	8.6%	7.8%	7.6%	6.8%	6.4%
Return on equity	13.5%	21.1%	8.2%	10.8%	9.9%	11.3%	11.1%	10.6%
Return on capital	8.2%	11.7%	5.6%	6.4%	6.3%	6.6%	6.5%	6.0%
Allowed ROE (EGD)	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%	8.39%
Allowed ROE (St. Lawrence)	10.5%	10.5%	10.5%	10.5%	10.5%			
Excluding Inter-company Debt, Inter-company Dividend Income and Interest Expense								
Cash flow/Debt	26.4%	32.8%	20.4%	19.4%	19.5%	21.7%	17.1%	16.8%
Total debt/Capital	49.2%	52.0%	49.2%	56.4%	55.4%	54.1%	59.3%	57.1%
EBITDA gross interest coverage (times)	4.83	5.41	4.45	4.65	4.41	4.51	3.92	4.06
EBIT gross interest coverage (times)	2.95	3.78	2.40	2.69	2.62	2.87	2.55	2.62
Debt/EBITDA (times)	2.86	2.16	3.75	3.85	3.59	3.32	4.12	3.90

Enbridge Gas Distribution Inc.

Report Date:
June 28, 2012

Rating

Debt Rated	Rating	Trend
Commercial Paper	R-1 (low)	Stable
Unsecured Debentures & Medium-Term Notes	A	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Stable

Rating History

Debt Rated	Current	2011	2010	2009	2008	2007
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A	A
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

Note:
All figures are in Canadian dollars unless otherwise noted.

Rating Report
Report Date:
March 15, 2013
Previous Report
June 28, 2012

DBRS
Insight beyond the rating.

Enbridge Gas Distribution Inc.

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The Company
Enbridge Gas Distribution Inc. (EGD) is a regulated natural gas distribution utility, serving approximately two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. EGD also distributes natural gas to approximately 15,700 customers in northern New York State through a wholly owned subsidiary, St. Lawrence Gas Company (approximately 2% of total revenue). EGD is an indirect wholly owned subsidiary of Enbridge Inc. (rated A (low)).

Commercial Paper Limit
$700 million

Recent Actions
September 14, 2012
Assigned Issuer Rating

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Ratings Update

DBRS has confirmed the ratings of Enbridge Gas Distribution Inc. (EGD or the Company) as listed above. The Company's rating is based on its low business risk, stable regulatory environment in Ontario, strong franchise area and stable financial profile.

EGD's low business risk profile is supported by a large customer base (approximately two million customers, the largest in Canada), which has allowed the Company to achieve operational efficiency and generate stable earnings and cash flow. In 2013, the rebasing year, EGD's approved return on equity (ROE) increased to 8.93% (8.39% in 2012) and distribution rates increased to $1,021 million ($1,004 million in 2012). However, the deemed equity component of the Company's capital structure remained unchanged at 36%. The Company benefits from a stable regulatory system, having no exposure to gas price risk in Ontario, where it generates approximately 98% of its revenue. EGD's franchise area (largely in the Greater Toronto Area) is viewed as one of the most rapidly growing and economically strong service areas in Canada. Approximately 94% of the Company's earnings are generated from relatively stable regulated distribution, transportation and storage business. The remainder is generated from the unregulated storage business, which benefits from strong demand due to its strategic locations.

EGD's financial profile remained stable in 2012, with all credit metrics being commensurate with DBRS's "A" rating guidelines. DBRS notes that the Company requires significant liquidity to finance working capital (mostly gas inventory for winter distributions). Given the low gas price environment, EGD's liquidity remains adequate to meet its operational needs. Over the medium term, moderate cash flow deficits are expected, due to the large capital expenditures (capex) program. However, EGD's current debt leverage of 55% is well within DBRS's "A" rating category, providing it with significant financial flexibility. DBRS expects the Company to remain prudent in funding its cash shortfalls and maintain its credit metrics within the "A" rating category.

Rating Considerations

Strengths
(1) Stable regulatory framework
(2) Strong franchise with a large customer base
(3) Reasonable balance sheet and credit metrics

Challenges
(1) Weather-related volume risk
(2) High dividend payout
(3) Free cash flow deficits

Financial Information

	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
Enbridge Gas Distribution Inc.	**For the year ended December 31**				
(CA$ millions)	**2012**	**2011**	**2010**	**2009**	**2008**
Net income before extra. Items	141	191	193	221	211
Cash flow from operations	489	491	467	504	483
Total debt in capital structure (1)	55.0%	55.1%	58.7%	57.8%	62.2%
EBIT gross interest coverage (times) (1)	2.26	2.49	2.62	2.87	2.55
Cash flow/Total debt (1)	16.4%	16.6%	16.9%	18.7%	15.1%
Total debt/EBITDA (times) (1)	4.68	4.48	4.15	3.85	4.67
Approved ROE	8.39%	8.39%	8.39%	8.39%	8.39%

(1) Excludes inter-company loans and/or inter-company prefered dividend income and interest expense.

Enbridge Gas Distribution Inc.

Report Date:
March 15, 2013

Rating Considerations Details

Strengths
(1) **Stable regulatory framework.** EGD's low risk business is underpinned by its gas distribution operations and a stable regulatory environment. Gas supply costs are adjusted quarterly and are passed through to customers. The Company has rebased its rates in 2013 under the cost-of-service (COS) framework. Beyond 2013, the company is expected to continue to operate under an IR framework.

(2) **Strong franchise with a large customer base.** EGD is the largest regulated natural gas distributor in Canada, serving approximately two million customers in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong and its large customer base allows it to achieve operational efficiency.

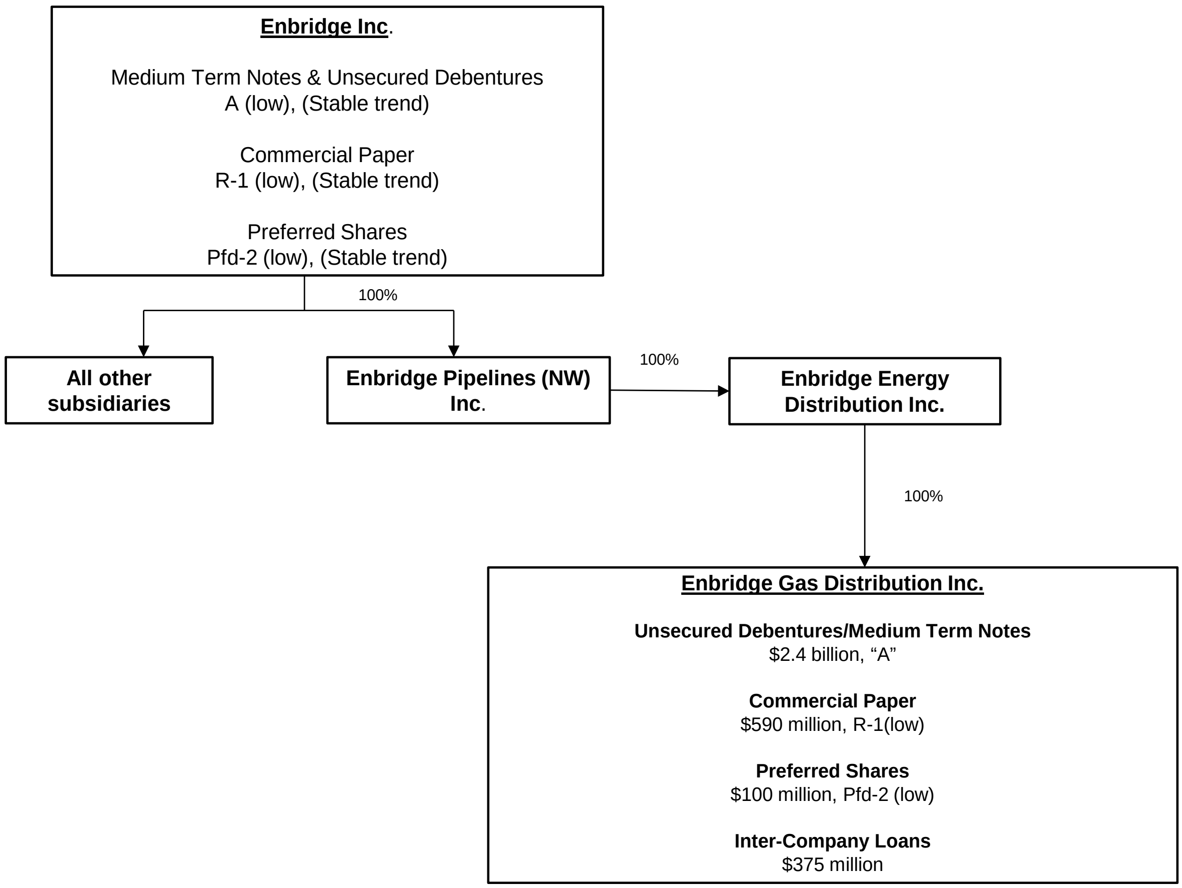
(3) **Reasonable balance sheet and credit metrics.** EGD maintains a reasonable balance sheet and credit metrics commensurate with the current ratings. EGD is committed to maintaining its capital structure within the regulatory approved level of 64% debt and 36% equity. The current debt leverage (55% in 2012) provides the Company with significant financial flexibility within DBRS's "A" rating category.

Challenges
(1) **Weather-related volume risk.** Weather remains the most significant risk, as forecast volumes — based on the normalized weather — are built into the Company's base rates, while actual usage varies with actual weather. Therefore, colder-than-normal weather in a given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. However, normalized weather is updated annually for rate-making purposes by incorporating the most recent weather trend, thus mitigating any significant sustained exposure to weather risk.

(2) **High dividend payout.** EGD has a high targeted dividend payout ratio of 90% to 100% and over the past five years, its dividend payout ratio (based on net income before extra items) has averaged around 106%. However, EGD's dividend payout is subject to maintaining its capital structure in line with the regulatory approved levels.

(3) **Free cash flow deficits.** Free cash flow deficits continued to be higher than historical in 2012 ($198 million) as a consequence of growing capex. Negative free cash flow is expected to continue in 2013, since capex is expected to increase to approximately $560 million.

Simplified Organizational Chart



Debt information as of December 31, 2012.

Enbridge Gas Distribution Inc.

Report Date:
March 15, 2013

Earnings and Outlook

	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
	For the year ended December 31				
(CA$ millions)	**2012**	**2011**	**2010**	**2009**	**2008**
Net gas distribution revenue	670	612	605	576	506
Gas transportation service revenue	345	421	390	449	505
Gas distribution margin	1,015	1,033	995	1,025	1,011
Other revenue (1)	113	103	108	108	94
Total revenue	1,128	1,136	1,103	1,133	1,105
EBITDA	639	658	666	699	684
EBIT	319	356	396	445	445
Earnings sharing	10	13	19	19	6
Intercompany dividend income	63	63	63	63	63
Interest expense (external)	(141)	(143)	(151)	(155)	(175)
Interest expense (intercompany)	(27)	(27)	(27)	(27)	(27)
Net income before extra. Items	141	191	193	221	211
Extra items	93	2	0	0	0
Reported net income	234	193	193	221	211

(1) Adjusted for $89 million recognition in regulatory asset related to other postretirement benefits in 2012.

Deemed equity (EGD)	36%	36%	36%	36%	36%
Approved ROE (EGD)	8.39%	8.39%	8.39%	8.39%	8.39%
Actual ROE	5.88%	8.88%	9.91%	11.32%	11.06%
Distribution rate base (millions) (2)	4,011	3,957	3,838	3,794	3,779

(2) Based on Canadian GAAP for regulatory purposes.

2012 Summary

- The Company's earnings are mainly generated from gas distribution operations (approximately 55% of 2012 total revenue) and gas transportation operations (28% of 2012 total revenue), with the remaining contributed by the storage business.
- Most of the gas distribution earnings are generated by EGD and a small portion (about 2% of revenues) is contributed by its wholly owned subsidiary, St. Lawrence Gas Company (SLG), a natural gas distributor in New York State.
- The storage business includes regulated and unregulated facilities, with the latter accounting for approximately 4% of overall earnings in 2012.
- Earnings in regulated operations are mainly driven by rate base growth and approved ROE (both of which remained stable in 2012), as well as weather, which was warmer in 2012 and resulted in a slight decrease in gas distribution margins.
- Transportation revenue has declined since 2008, mainly due to transportation customers shifting to system gas. As a result, net gas distribution revenues have increased.
- Earnings sharing represents EGD's 50% share of actual returns on equity (excluding the effect of weather) in excess of 100 basis points above the allowed ROE.
- Dividend income represents the cash income from EGD's $825 million investment in its affiliate (IPL System Inc.), the holder of the Company's $375 million inter-company loan outstanding at December 31, 2012. The interest expense on this loan was $27 million in 2012.

2013 Outlook

- The Company's earnings, under normal weather conditions, should increase moderately in 2013, driven primarily by customer growth in the Company's franchise areas and the increase in its rate base ($4,162 million for 2013).
- Following the COS application, the Company's ROE increased to 8.93% for 2013 from 8.39% in 2012 and its deemed equity remained unchanged at 36%.
- The Company expects to add between 35,000 and 40,000 customers annually.

Financial Profile

	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
	For the year ended December 31				
(CA$ millions)	**2012**	**2011**	**2010**	**2009**	**2008**
Net income before extra. Items (3)	141	191	193	221	211
Depreciation & amortization	320	302	270	254	239
Deferred income taxes/Other	28	(2)	4	29	33
Cash flow from operations	489	491	467	504	483
Dividends paid	(208)	(220)	(210)	(185)	(163)
Capex	(479)	(475)	(365)	(370)	(411)
Free cash flow before WC	(198)	(204)	(108)	(51)	(91)
Changes in working capital (WC)	77	15	45	467	(115)
Net free cash flow	(121)	(189)	(63)	416	(207)
Acquisitions (2)	0	0	0	0	0
Assets sales/Divestitures	72	0	0	0	0
Net changes in equity (2)	0	0	0	0	0
Net changes in debt	38	164	58	(469)	261
Other (3)	5	21	(2)	(15)	6
Change in cash	(6)	(4)	(7)	(68)	60
Total external debt	2,988	2,950	2,766	2,693	3,193
Inter-company debt	375	375	375	375	375
Total debt/Capital (1)	55.0%	55.1%	58.7%	57.8%	62.2%
EBIT interest coverage (times) (1)	2.26	2.49	2.62	2.87	2.55
Cash flow/Total debt (1)	16.4%	16.6%	16.9%	18.7%	15.1%
Dividends/Cash flow	42.1%	44.4%	44.5%	35.9%	32.7%
Dividend payout ratio	147.5%	115.2%	108.8%	83.7%	77.2%

(1) Excludes inter-company loans and/or inter-company dividend income and interest expense.

(2) In August 2011, EGD issued $66 million to finance its $66 million solar asset acquisition from Enbridge Inc.

(3) Adjusted for $89 million recognition in regulatory asset related to other postretirement benefits in 2012.

2012 Summary

- In 2012, the Company's cash flow from operations remained relatively stable. The $2 million decrease is due mainly to the warmer than expected weather and continued decrease in transportation volumes.
- Capex in 2012 remained high, above depreciation, as a result of system improvements, upgrades and expansion.
- EGD has a targeted dividend payout ratio of 90% to 100%. This is subject to maintaining its capital structure in line with the regulatory approved levels.
- The company financed its free cash flow deficit through debt and asset sales in 2012. The Company's capital structure remained stable and was in line with the regulatory capital structure of 36% equity.
- Other key credit metrics: EBIT-interest coverage and cash flow-to-debt ratio remained stable and were in line with the "A" rating category.

2013 Outlook

- Capex for 2013 is expected to be approximately $560 million on capital projects and maintenance. Capital projects largely include the Greater Toronto Area, Franklin County Expansion and Ottawa re-enforcement project.
- As a result, the Company is expected to generate free cash flow deficits of approximately $250 million to $280 million in 2013. DBRS expects EGD to remain prudent in its financing of cash shortfalls in order to maintain its balance sheet leverage within "A" rating guidelines.

Long-Term Debt Maturities and Liquidity

Bank Lines/Liquidity

Credit Facilities				As at Dec. 31, 2012
(CA$ millions)	**Total Facilities**	**Drawn**	**Available**	**Maturity**
Committed lines of credit	700	580	120	2014
Uncommitted lines of credit*	12	10	2	2014
Total	712	590	122	

* The uncommitted lines of credit are at St. Lawrence Gas, Inc.

- EGD requires relatively high liquidity to support its highly volatile (heavily influenced by gas prices) and seasonal working capital needs and increased capex.
- The Company's Commercial Paper program is fully backed by the $700 million, 364-day revolving committed credit facility ($120 million available as at December 31, 2012), which was extended in August 2012 for an additional year to August 2013, with a maturity date of August 2014.
- DBRS views EGD's current liquidity as adequate. Nevertheless, a combination of cold weather and high gas prices could exhaust the Company's available liquidity. However, this scenario is unlikely, given the current low gas price environment.

Debt	As at Dec. 31, 2012 (CA$ millions)
Commercial paper	580
Other ST borowings	21
LT debt	2,387
Total	**2,988**

Long-Term Debt Maturity Schedule	<1 year	1-3 years	3-5 years	Thereafter	Total
As at Dec. 31, 2012 (CA$ millions)	0	400	200	1,787	2,387

- Debt refinancing remains manageable, despite $400 million of debt due in the coming two years.
- The $800 million shelf prospectus filed in November 2010 expired during the fourth quarter of 2012. As a result, the Company filed an $800 million shelf prospectus in January 2013 that will be effective for a 25-month period.
- EGD is subject to an EBIT-interest covenant of two times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
  - The covenant does not apply to debt issuance for refinancing.
  - The Company was in compliance with the test at fiscal year-end 2012.

Inter-Company Debt
- As of March 31, 2012, EGD owned $825 million of Class D, non-voting redeemable, retractable preferred shares of IPL System Inc. (IPL), which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans, which is deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company.

Regulation

Regulatory Overview

The Ontario Energy Board (OEB) regulates EGD's gas storage, transmission and distribution businesses. Consumers in Ontario have been able to choose their natural gas supplier since 1985. The gas purchase cost is passed on to customers through quarterly adjustments; as a result, the Company's distribution margin is not impacted by the gas purchase cost.

Gas Distribution: Ontario

- In January 2012, the Company filed an application with the OEB to set rates for 2013 on a COS basis and the OEB issued its final decision on February 7, 2013. The OEB approved a distribution revenue of $1,021 million for 2013 (95% of the requested amount; $1,004 million in 2012) effective January 1, 2013.
- The Company's ROE increased for 2013 to 8.93% from 8.39% in 2012 and the deemed equity of 36% remained unchanged for 2013.
- The $89 million in OPEB costs has been approved for recovery over a 20-year period commencing in 2013 on a straight-line basis. The rate order further provided for future OPEB and pension costs, determined on an accrual basis, to be recovered in rates.
- The Company is allowed to have several costs and deferred accounts outside of revenue escalation formula, including capex invested in new power generation and expenses above a defined threshold.
- EGD will retain earnings in excess of the approved ROE up to 100 basis points and will share the actual return on the approved equity level (excluding the effects of weather) in excess of 100 basis points above the approved ROE equally with customers under the IR framework.

Gas Distribution: New York

- The Company owns SLG, which provides natural gas distribution services to 15,700 customers in New York State.
- The Company is regulated by the New York State Public Service Commission under COS and is viewed as relatively stable.
- The approved ROE for 2012 was 10.5% on a deemed equity of 50%. Any earnings above 11% will be shared equally with customers. SLG had no earnings sharing in 2012, 2011 and 2010. SLG will continue to operate under the existing COS agreement in 2013.
- Gas supply costs are adjusted annually.
- In July 2012, SLG received regulatory approval to expand its operations to Franklin County in New York State.

Gas Storage

- EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates.
- Revenues from the unregulated storage business have increased since the OEB's change of EGD's pricing policy in 2007.

Enbridge Gas Distribution Inc.

Report Date:
March 15, 2013

Enbridge Gas Distribution Inc.

Balance Sheet	USGAAP	USGAAP	CGAAP		USGAAP	USGAAP	CGAAP
(CA$ millions)	**Dec. 31**	**Dec. 31**	**Dec. 31**		**Dec. 31**	**Dec. 31**	**Dec. 31**
Assets	**2012**	**2011**	**2010**	**Liabilities & Equity**	**2012**	**2011**	**2010**
Cash & equivalents	3	6	13	S.T. borrowings	601	563	349
Accounts receivable	324	401	457	Current portion LTD	0	0	150
Inventories	326	380	400	Accounts payable	59	78	57
Others	270	265	345	Deferred tax	0	2	5
				Others	589	638	793
Total Current Assets	**923**	**1,052**	**1,215**	**Total Current Liabilities**	**1,249**	**1,281**	**1,354**
Net fixed assets	5,532	5,336	4,458	Long-term debt (LTD)	2,387	2,387	2,267
Future income tax assets	0	0	0	Deferred income taxes	362	304	171
Goodwill & intangibles	177	170	167	Loan from affiliate	375	375	375
Investments in affiliates	825	825	825	Other L.T. liabilities	1,094	1,025	1,058
Deferred and others	432	365	487	Preferred shares	100	100	100
				Shareholders equity	2,322	2,276	1,827
Total Assets	**7,889**	**7,748**	**7,152**	**Total Liab. & SE**	**7,889**	**7,748**	**7,152**

	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
Balance Sheet &	**For the year ended December 31**				
Liquidity & Capital Ratios	**2012**	**2011**	**2010**	**2009**	**2008**
Current ratio (times)	0.74	0.82	0.90	0.61	0.66
Total debt in capital structure	57.9%	58.1%	61.8%	60.9%	64.8%
Cash flow/Total debt	14.5%	14.8%	14.9%	16.4%	13.5%
Cash flow/Capex (times)	1.02	1.03	1.28	1.36	1.17
(Cash flow - Dividends)/Capex (times)	0.59	0.57	0.70	0.86	0.78
Dividend payout ratio	147.5%	115.2%	108.8%	83.7%	77.2%
Dividends/Cash flow	42.1%	44.4%	44.5%	35.9%	32.7%
Profitability Ratios					
EBITDA margin	56.6%	57.9%	60.4%	61.7%	61.9%
EBIT margin	28.3%	31.3%	35.9%	39.3%	40.3%
Profit margin	12.5%	16.8%	17.5%	19.5%	19.1%
Return on equity	5.9%	8.9%	9.9%	11.3%	11.1%
Return on capital	4.5%	5.7%	6.3%	6.6%	6.5%
Allowed ROE (EGD)	8.39%	8.39%	8.39%	8.39%	
Allowed ROE (St. Lawrence)	10.50%	10.5%	10.5%		
Excluding Inter-company Debt, Inter-company Dividend Income and Interest Expense					
Cash flow/Debt	16.4%	16.6%	16.9%	18.7%	15.1%
Total debt/Capital	55.0%	55.1%	58.7%	57.8%	62.2%
EBITDA gross interest coverage (times)	4.53	4.60	4.41	4.51	3.92
EBIT gross interest coverage (times)	2.26	2.49	2.62	2.87	2.55
Debt/EBITDA (times)	4.68	4.48	4.15	3.85	4.67

Enbridge Gas Distribution Inc.

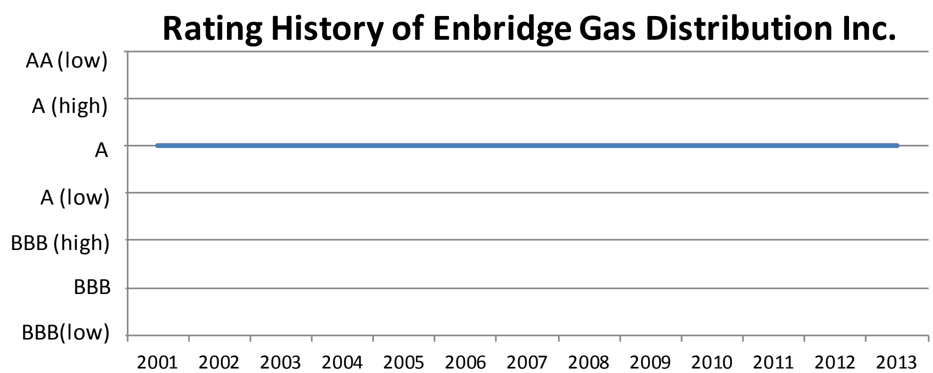
Report Date:
March 15, 2013

Rating

Debt Rated	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating History

Debt Rated	Current	2012	2011	2010	2009	2008
Issuer Rating	A	A	NR	NR	NR	NR
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A	A
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)



Note:
All figures are in Canadian dollars unless otherwise noted.

Rating Report
Report Date:
March 12, 2014
Previous Report
March 15, 2013

DBRS
Insight beyond the rating.

Enbridge Gas Distribution Inc.

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The Company
Enbridge Gas Distribution Inc. (EGD) is a regulated natural gas distribution utility, serving over two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. EGD also distributes natural gas to approximately 15,800 customers in northern New York State through a wholly owned subsidiary, St. Lawrence Gas Company, Inc. (approximately 0.6% of 2013 consolidated EBIT). EGD is an indirect wholly owned subsidiary of Enbridge Inc. (rated A (low)).

Commercial Paper Limit
$700 million

Recent Actions
March 15, 2013
Confirmed

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Ratings Update

DBRS has confirmed the ratings of Enbridge Gas Distribution Inc. (EGD or the Company) as listed above. The Company's ratings are based on its low-risk business profile, supported by a stable regulatory environment in Ontario and a strong franchise area with a large customer base. The confirmation factors in DBRS's expectation that the Company will continue to finance its free cash flow deficits to maintain its credit ratios within DBRS's "A" rating category.

EGD's business risk profile is indicative of an "A" rating, underpinned by the following factors: (1) EGD operates under a stable regulatory system. In 2013, following the five-year Incentive Regulation (IR) period, EGD operated under the Cost-of Service (COS) system. The move to COS methodology provided the Company with an opportunity to rebase and earn a higher return on equity (ROE) (8.93% compared with 8.39% in the IR period), while the deemed equity remained unchanged at 36%, which is relatively low compared with other jurisdictions. Natural gas supply costs continue to be passed through to EGD's customers. (2) EGD's franchise area, primarily the Greater Toronto Area (GTA), is viewed as one of the most economically strong service areas in Canada. In addition, the Company's large customer base of over two million should provide it with a critical mass to meet or exceed its efficiency factor during the next IR term (2014-2018). The Company filed an IR application for the 2014-2018 period in July 2013, and the decision by the Ontario Energy Board (OEB) is expected in Q2 2014. Should the OEB render an unfavourable decision to the extent that it may have a materially negative impact on the Company's future earnings and cash flow, a negative rating action could follow (although this will not likely be the case).

EGD's financial profile reflects an "A" rating, with all credit metrics remaining solidly within the current rating range. However, two concerns over the near to medium term are as follows: (1) Significant liquidity is required to finance EGD's volatile working capital (mostly gas inventory for winter distributions). EGD's liquidity is currently viewed as adequate to meet its operational needs given low natural gas prices. Should natural gas prices increase significantly, DBRS expects EGD to properly manage its liquidity to cope with that situation. (2) Large free cash flow deficits are expected over the next two years because of the $686.5 million GTA Expansion project. EGD's parent (Enbridge Inc.) is expected to continue providing financial support for EGD. DBRS expects EGD to finance its cash flow shortfalls while maintaining the debt leverage within the regulatory capital structure and all other credit metrics within the DBRS "A" rating range. This project has been approved by the OEB and should provide good earnings growth once it is in service, which is expected to occur by the end of 2015.

Rating Considerations

Strengths
(1) Stable regulatory framework
(2) Strong franchise with a large customer base
(3) Reasonable balance sheet/solid credit metrics

Challenges
(1) Weather-related volume risk
(2) Large capex program
(3) High dividend payout

Financial Information

Enbridge Gas Distribution Inc. (CA$ millions)	For the year ended December 31 2013	2012	2011	2010	2009
Net income before extra. Items	217	119	171	193	221
Cash flow from operations	524	472	473	467	504
Total debt in capital structure (1)	55.7%	55.5%	55.1%	58.7%	57.8%
EBIT gross interest coverage (times) (1)	2.60	2.05	2.29	2.62	2.87
Cash flow/Total debt (1)	16.4%	15.8%	16.0%	16.9%	18.7%
Total debt/EBITDA (times) (1)	4.75	4.91	4.68	4.15	3.85
Approved ROE	8.93%	8.39%	8.39%	8.39%	8.39%

(1) Excludes inter-company loans and/or inter-company dividend income and interest expense.
Note: Reported under U.S. GAAP except 2010 and 2009, which were under Canadian GAAP.

Rating Considerations Details

Strengths

(1) **Stable regulatory framework.** The regulatory framework in Ontario and the nature of the Company's natural gas distribution, transportation and storage operations , which are mostly regulated, have underpinned the Company's strong business risk profile. The Ontario regulatory regime provides the Company with the following benefits that support the "A" rating: (a) gas supply costs are passed through to customers, with quarterly adjustments to the rates; (b) the 2013 Settlement (under the COS framework) allowed EGD to rebase its rate base, to recover prudently incurred operating costs, and to earn a higher ROE than the 2008-2012 period; and (c) beyond 2013, the Company is expected to continue to operate under an IR framework (2014-2018), which affords the Company an opportunity to earn the allowed ROE through its operational efficiency.

(2) **Strong franchise with a large customer base.** EGD is the largest regulated natural gas distributor in Canada, serving over two million customers (2.065 million active customers at the end of 2013) in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong, and its large customer base allows it to achieve operational efficiency. This is an important consideration for when the Company begins operating under the next IR term where the Company needs to achieve operational efficiency either equal to or better than the productivity factor in the IR-formula.

(3) **Reasonable balance sheet and solid credit metrics.** EGD maintains a reasonable balance sheet and credit metrics commensurate with the current ratings. EGD is committed to maintaining its capital structure within the regulatory approved level of 64% debt and 36% equity. The current debt leverage (55.7% at the end of 2013) provides the Company with some financial flexibility with respect to its future financing plan for the GTA project.

Challenges

(1) **Weather-related volume risk.** Weather risk remains significant as forecast volumes (based on the normalized weather) are built into the Company's base rates, while actual usage varies with actual weather. Therefore, colder-than-normal weather in a given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. However, normalized weather is updated annually by incorporating the most recent weather trend, thus mitigating any significant sustained exposure to weather conditions.

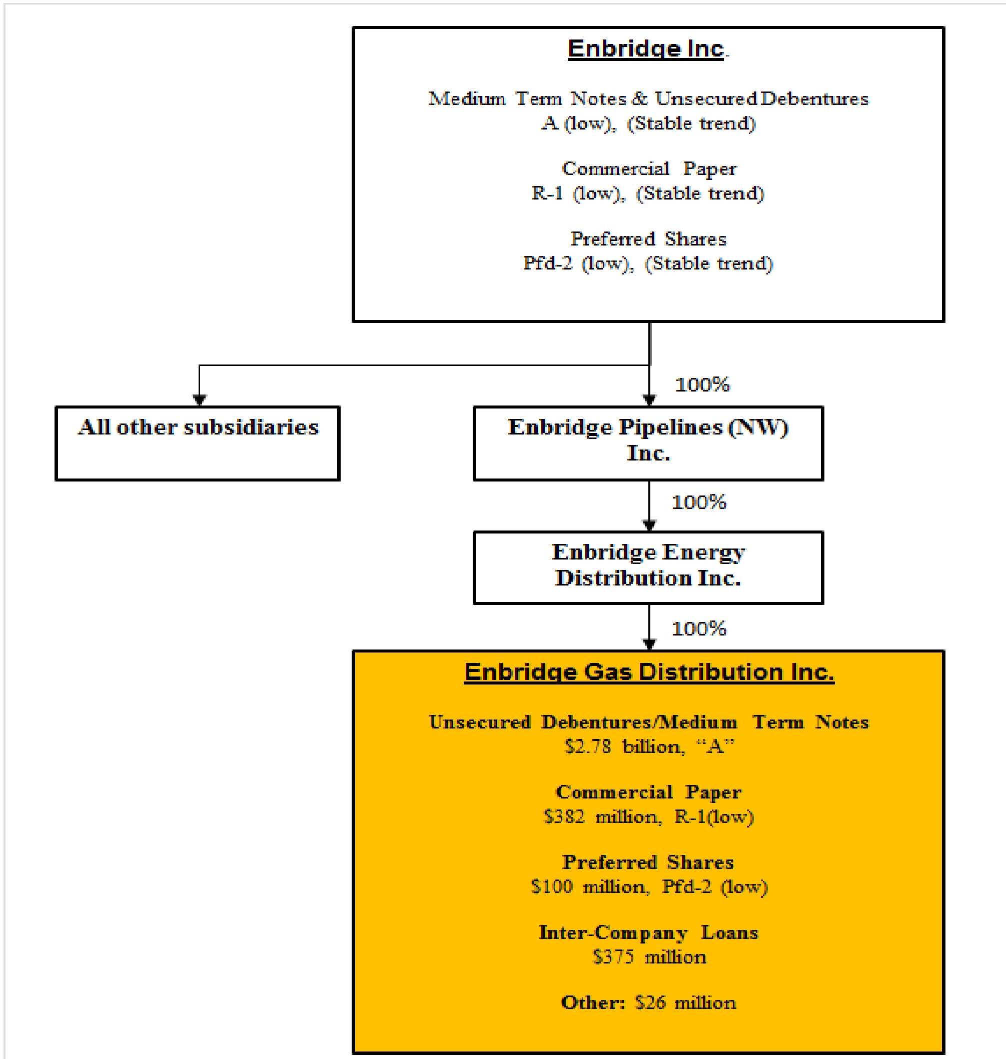
(2) **Large capex program.** The Company has a large capex program over the next two years, with $690 million estimated for 2014 and a larger amount expected for 2015. This large capex reflects the following factors: (a) high capex spending is required for system improvements and upgrades and (b) the financing of the 2014 portion of the GTA Expansion Project (see the GTA Project below). As a result, EGD is expected to generate large free cash flow deficits and will require external funds. DBRS expects the Company to maintain its debt leverage within the regulatory approved level and to maintain all other metrics within the DBRS "A" rating range, while carrying out its financing plan. DBRS also expects Enbridge Inc. to continue providing equity support for the Company in a timely fashion.

(3) **High dividend payout.** In general, EGD has a dividend payout ratio target of 90% to 100%, which DBRS views as high. Over the past five years, its dividend payout ratio, based on net income before extra items, has averaged around 116%. However, EGD's dividend payout is subject to maintaining the Company's capital structure in line with the regulatory approved level.

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Simplified Organizational Chart



Debt information as of December 31, 2013.

The Great Toronto Area Expansion Project (the GTA Project)

- The purpose of the GTA Project is to expand EGD's natural gas distribution system in the GTA to meet the demands of customer growth and to continue delivering safe and reliable natural gas to current and future customers.
- The proposed GTA project will consist of two segments of pipeline and related facilities to upgrade the existing system that delivers natural gas to several municipalities in Ontario.
- In January 2014, the OEB approved the project with the capital cost of $686.5 million.
- Construction is expected to start in late 2014, with completion targeted for the end of 2015.
- The Company is expected to fund this project with an appropriate mix of debt and equity to maintain its capital structure in line with the regulatory approved structure. DBRS expects the Company's parent to continue providing equity support for this project.
- During the construction, the Company's cash flow metrics are expected to weaken slightly from the 2013 level. However, once the project is fully in service, these metrics should return to the current level.

DBRS

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Earnings and Outlook

Enbridge Gas Distribution Inc.	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP
	For the year ended December 31				
(CA$ millions)	2013	2012	2011	2010	2009
Net gas distribution revenue	741	640	584	605	576
Gas transportation service revenue	328	345	421	390	449
Gas distribution margin	1,069	985	1,005	995	1,025
Other revenue (1)	99	113	103	108	108
Total revenue	1,168	1,098	1,108	1,103	1,133
EBITDA	672	609	630	666	699
EBIT	368	289	328	396	445
Earnings sharing	0	10	13	19	19
Intercompany dividend income	63	63	63	63	63
Interest expense (external)	(142)	(141)	(143)	(151)	(155)
Interest expense (intercompany)	(27)	(27)	(27)	(27)	(27)
Net income before extra. Items	217	119	171	193	221
Extra items	0	93	2	0	0
Reported net income	217	212	173	193	221

(1) Adjusted for $89 million recognition in regulatory asset related to other postretirement benefits in 2012.

	2013	2012	2011	2010	2009
Deemed equity (EGD)	36%	36%	36%	36%	36%
Approved ROE (EGD)	8.93%	8.39%	8.39%	8.39%	8.39%
Distribution rate base (CA$ millions)	4,162	4,011	3,957	3,838	3,794

2013 Summary

- **Overall:** Higher earnings (before extraordinary items) reflected higher gas distribution earnings in Ontario due to colder weather, customer growth and higher allowed ROE. This increase was partially offset by (1) the elimination of earnings sharing under the 2013 Settlement and (2) lower transportation revenues.
- EGD's earnings are mainly generated from gas distribution operations (approximately 63% of 2013 total revenue) and gas transportation operations (28% of 2013 total revenue), with the storage business largely contributing the remaining earnings percentage.
- Most of the gas distribution earnings are generated by the Company's Ontario operations; a small portion (about 0.6% of EBIT) is contributed by its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (SLG), a natural gas distributor in New York State.
- The decline of transportation revenues over the past three years reflected an eroding customer base caused by customer switch. By the end of 2013, the number of active customers was 251,434 (versus 364,027 in 2011).
- The storage business includes regulated and unregulated facilities, with the latter accounting for approximately 2.1% of EGD's consolidated EBIT in 2013.
- Beside weather impact, earnings in regulated operations are mainly driven by rate base growth, approved ROE (which was higher in 2013), and the Company's operational efficiency during the IR period.
- The earnings sharing was no longer in effect in 2013 in accordance with the 2013 Settlement. During the 2008-2012 term, the sharing mechanism represented EGD's 50% share of actual ROE (excluding the effect of weather) in excess of 100 basis points above the allowed ROE.
- Dividend income represents the cash income from EGD's $825 million investment in its affiliate (IPL System Inc.), the holder of the Company's $375 million inter-company loan outstanding at December 31, 2013. The interest expense on this loan was $27 million in 2013.

2014 Outlook

- The earnings outlook for 2014 is expected to be positive, given the cold weather conditions in Q1 2014. In the absence of an adverse regulatory decision on the Company's IR application for 2014-2018, customer growth is expected to continue to have a positive impact on EGD's 2014 earnings. EGD's ability to achieve a production efficiency equal to or better than the productivity factor in the IR-formula (which has yet to be determined by the OEB) is critical to attaining the approved ROE.
- Should the GTA Project be brought in service on time (i.e., the end of 2015) and within the approved budget, earnings beyond 2015 are expected to increase meaningfully.

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Financial Profile

Enbridge Gas Distribution Inc.	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP
	For the year ended December 31				
(CA$ millions)	**2013**	**2012**	**2011**	**2010**	**2009**
Net income before extra. items	217	119	171	193	221
Depreciation & amortization	304	320	302	270	254
Deferred income taxes/Other	3	33	0	4	29
Cash flow from operations	524	472	473	467	504
Dividends paid	(202)	(208)	(220)	(210)	(185)
Capex	(553)	(452)	(448)	(365)	(370)
Free cash flow before WC	(231)	(188)	(195)	(108)	(51)
Changes in working capital (WC)	(86)	71	15	45	467
Net free cash flow	(317)	(117)	(180)	(63)	416
Acquisitions	0	0	0	0	0
Assets sales/Divestitures	0	72	0	0	0
Net changes in equity	150	0	0	0	0
Net changes in debt	192	38	164	58	(469)
Other (*)	16	1	12	(2)	(15)
Change in cash	41	(6)	(4)	(7)	(68)
Total external debt	3,192	2,988	2,950	2,937	2,766
Inter-company debt	375	375	375	375	375
Total debt/Capital (1)	55.7%	55.5%	55.1%	58.7%	57.8%
EBIT interest coverage (times) (1)	2.60	2.05	2.29	2.62	2.87
Cash flow/Total debt (1)	16.4%	15.8%	16.0%	16.9%	18.7%
Dividends/Cash flow	38.5%	44.1%	46.5%	45.0%	36.7%
Dividend payout ratio	93.1%	174.8%	128.7%	108.8%	83.7%

(1) Excludes inter-company loans and/or inter-company dividend income and interest expense.
(*) Adjusted for $89 million recognition in regulatory asset related to other postretirement benefits in 2012.

2013 Summary

- EGD maintained a reasonable financial profile for the “A” rating category in 2013, with all credit metrics either remaining stable or improving slightly from the prior year.
- A large cash flow deficit was generated in 2013 mainly because of an increase in capex, which can largely be attributed to higher spending on improvements and upgrades to the distribution system and customer growth projects (including the Franklin County Expansion Project (the Franklin Project) in New York State).
- The dividend policy remained unchanged from previous years, with the payout ratio target of 90% to 100%, subject to EGD’s regulatory approved capital structure.
- The 2013 free cash flow deficit was mainly financed with a mix of debt and equity issuance. The issuance of equity was to maintain the capital structure within the regulatory structure (36% equity in 2013).

Note: In 2012, EGD sold its 99.9% partnership interest in Project Amherstburg (a power project) to Enbridge Income Fund (an affiliated entity) for $72 million. The cash proceeds were used to finance a portion of the Company’s cash flow deficit that year.

2014 Outlook

- Capex for 2014 is estimated to be approximately $690 million for capital projects and maintenance. This amount is much higher than the past three-year average of $484 million. This increase largely reflects the 2014 portion of capex spending on the GTA project.
- As a result, the Company is expected to generate a large free cash flow deficit in 2014. DBRS expects (1) EGD to remain prudent in its financing of cash shortfalls and (2) the Company’s parent to continue injecting equity into EGD, as it has in the past, to maintain the Company’s capital structure within the regulatory approved level and within DBRS’s “A” rating guidelines for a gas distribution company.

DBRS

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Liquidity and Long-Term Debt Maturities

Bank Lines/Liquidity

Credit Facilities				As at Dec. 31, 2013
(CA$ millions)	**Total Facilities**	**Drawn**	**Available**	**Maturity**
Committed line of credit	700	370	330	2015
Uncommitted line of credit*	13	12	1	2019
Total	713	382	331	

* The uncommitted line of credit is at St. Lawrence Gas Company, Inc.

- EGD requires relatively high liquidity to support its volatile and seasonal working capital needs, which are heavily influenced by natural gas prices.
- The Company has a commercial paper program of $700 million, which is fully backed by the $700 million, 364-day revolving unsecured committed credit facility, maturing in August 2015.
- DBRS views EGD's current liquidity as sufficient to finance its working capital requirements. However, a combination of cold weather and high gas prices could exhaust the Company's available liquidity, although this scenario is unlikely, given the current low gas price environment.

Debt	As at Dec. 31, 2013
(CA$ million)	
Commercial paper	370
Other ST borowings	23
LT debt	2,399
LT debt mature in one year	400
Total	**3,192**

Long-Term Debt Maturity

Long-Term Debt Maturity Schedule	2014	2015	2016	2017	2018	Thereafter	Total
(CA$ million)							
As at Dec. 31, 2013 (CA$ millions)	400	1	2	201	2	2,193	2,799

- Given the Company's strong credit profile, the refinancing risk for the $400 million in medium-term notes due in 2014 remains manageable.
- EGD is subject to an EBIT-interest covenant of two times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
  - The covenant does not apply to debt issuances for debt refinancing.
  - The Company was in compliance with the test at the end of 2013.

Inter-Company Debt

- As of December 31, 2013, EGD owned $825 million of Class D, non-voting redeemable, retractable preferred shares of IPL System Inc. (IPL), which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans, which is deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years, and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company.
- DBRS excludes this debt from its calculation of the Company's capital structure.

Regulation

Regulatory Overview

The OEB regulates EGD's gas storage, transmission and distribution businesses. Consumers in Ontario have been able to choose their natural gas supplier since 1985. The gas purchase cost is passed on to customers through quarterly adjustments; as a result, the Company's distribution margin is not affected by the gas purchase cost, subject to variances between total natural gas distributed by the Company and the amount of natural gas billed or billable to customers.

Gas Distribution: Ontario

- In 2013, the Company operated under the COS methodology pursuant to the 2013 Settlement. The Company retained the previous deemed equity level (36%). The allowed ROE was 8.93% (versus 8.39% in 2012). The earning sharing mechanism established under the 2008-2012 IR framework did not apply in the 2013 Settlement.
- The 2013 Settlement gave EGD the right to recover other post-retirement benefits (OPEB) costs of $89 million over a 20-year period, commencing 2013. It also provided for OPEB and pension costs determined on an accrued basis, to be recovered in rates.
- In July 2013, the Company filed an application for setting rates through a customized IR mechanism for the 2014-2018 period. A regulatory decision on the Company's application is expected in Q2 2014.
- DBRS does not expect the decision to have any changes that could have a negatively material impact on the Company's earnings and cash flows.

Gas Storage: Ontario

- EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers (since November 2006) within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates.

Transportation: National Energy Board (NEB)

- TransCanada Pipelines Limited (TransCanada) transports approximately 60% (7.4 billion cubic metres) of the annual natural gas requirements of EGD's customers; the remainder is obtained through contracts with Alliance Pipeline Canada, Alliance Pipeline U.S. and Vector Pipeline.
- The Company has Firm Transportation (FT) contracts with TransCanada for a portion of the requirement. Effective July 2013, the NEB approved new tolls on the FT service for TransCanada. Under the new tolls, the Company is required to pay TransCanada the demand component regardless of the volume transported.
- Transportation costs are passed through to customers.

Gas Distribution: New York

- The Company owns SLG, which provides natural gas distribution services to 15,800 customers in New York State.
- SLG is regulated by the New York State Public Service Commission under COS and is viewed as relatively stable.
- The approved ROE for 2013 was 10.5% (also 10.5% in 2012) on a deemed equity of 50% (also 50% in 2012). Any earnings above 11% will be shared equally with customers. SLG has had no earnings sharing since 2010 and will continue to operate under the existing COS agreement in 2014.
- SLG has no exposure to natural gas price risk, with gas supply costs being adjusted annually.
- SLG started construction in August 2012, following the July 2012 regulatory approval of the Franklin Project. The total capital cost over the five-year period is estimated to be USD 45 million. SLG is estimated to have spent approximately USD 38 million by the end of 2013. The Franklin Project is expected to add 4,400 potential customers to the system.

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Enbridge Gas Distribution Inc.

Balance Sheet (US GAAP)

(CA$ millions)	Dec. 31	Dec. 31	Dec. 31		Dec. 31	Dec. 31	Dec. 31
Assets	**2013**	**2012**	**2011**	**Liabilities & Equity**	**2013**	**2012**	**2011**
Cash & equivalents	44	3	6	S.T. borrowings	393	601	563
Accounts receivable	341	324	401	Current portion LTD	400	0	0
Inventories	382	341	380	Accounts payable	46	59	78
Others	365	281	265	Deferred tax	0	0	2
				Others	723	671	638
Total Current Assets	**1,132**	**949**	**1,052**	**Total Current Liabilities**	**1,562**	**1,331**	**1,281**
Net fixed assets	5,869	5,532	5,336	Long-term debt (LTD)	2,399	2,387	2,387
Future income tax assets	0	0	0	Deferred income taxes	395	362	304
Goodwill & intangibles	174	177	170	Loan from affiliate	375	375	375
Investments in affiliates	825	825	825	Other L.T. liabilities	1,026	1,094	1,025
Deferred and others	379	432	365	Preferred shares	100	100	100
				Shareholders equity	2,522	2,266	2,276
Total Assets	**8,379**	**7,915**	**7,748**	**Total Liab. & SE**	**8,379**	**7,915**	**7,748**

	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP
Balance Sheet &	**For the year ended December 31**				
Liquidity & Capital Ratios	**2013**	**2012**	**2011**	**2010**	**2009**
Current ratio (times)	0.72	0.71	0.82	0.90	0.61
Total debt in capital structure	58.4%	58.4%	58.1%	61.8%	60.9%
Cash flow/Total debt (*)	14.6%	14.0%	14.2%	14.9%	16.4%
Cash flow/Capex (times)	0.95	1.04	1.06	1.28	1.36
(Cash flow - Dividends)/Capex (times)	0.58	0.58	0.56	0.70	0.86
Dividend payout ratio	93.1%	174.8%	128.7%	108.8%	83.7%
Dividends/Cash flow	38.5%	44.1%	46.5%	45.0%	36.7%
(*) debt includes inter-company debt					
Profitability Ratios					
EBITDA margin	57.5%	55.5%	56.9%	60.4%	61.7%
EBIT margin	31.5%	26.3%	29.6%	35.9%	39.3%
Profit margin	18.6%	10.8%	15.4%	17.5%	19.5%
Return on equity	8.7%	5.0%	N/A	9.9%	11.3%
Return on capital	5.9%	4.4%	N/A	6.3%	6.6%
Allowed ROE (EGD)	8.93%	8.39%	8.39%	8.39%	8.39%
Allowed ROE (St. Lawrence)	10.50%	10.5%	10.5%		
Excluding Inter-company Debt, Inter-company Dividend Income and Interest Expense					
Cash flow/Debt	16.4%	15.8%	16.0%	16.9%	18.7%
Total debt/Capital (1)	55.7%	55.5%	55.1%	58.7%	57.8%
EBITDA gross interest coverage (times)	4.73	4.32	4.41	4.41	4.51
EBIT gross interest coverage (times)	2.60	2.05	2.29	2.62	2.87
Debt/EBITDA (times)	4.75	4.91	4.68	4.15	3.85

(1) Includes operating leases.

Enbridge Gas Distribution Inc.

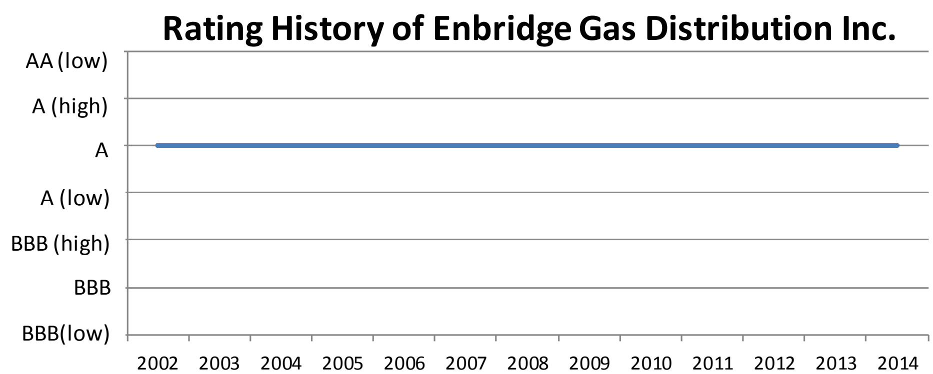
Report Date:
March 12, 2014

Rating

Debt Rated	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating History

Debt Rated	Current	2013	2012	2011	2010	2009
Issuer Rating	A	A	A	NR	NR	NR
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A	A
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)



Note:
All figures are in Canadian dollars unless otherwise noted.

Rating Report

Enbridge Gas Distribution Inc.

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DBRS
Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating Update

On March 13, 2015, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debentures & Medium-Term Notes (MTNs) rating of Enbridge Gas Distribution Inc. (EGD or the Company) at "A," the Company's Commercial Paper (CP) rating at R-1 (low) and its Cum. & Cum. Redeemable Convertible Preferred Shares at Pfd-2 (low). All trends are Stable. The Company's ratings are based on its low-risk business profile, supported by a reasonable and stable regulatory environment in Ontario and a strong franchise area with a large customer base of over two million. The confirmation incorporates risk faced by the Company with respect to financing and managing its $756 million Greater Toronto Area Project (GTA Project). The Stable trends factor in DBRS's expectation that (1) the GTA Project will be completed on time (expected by the end of 2015) and within budget, and (2) the Company will finance free cash flow deficits (as a result of the GTA Project and/or increased working capital needs due to rising natural gas prices) in an appropriate manner to maintain its credit ratios consistent with DBRS's "A" rating category, with leverage within the regulatory capital structure of 64% debt.

EGD's business risk profile remains strong and consistent with its current ratings, underpinned by the following factors: (1) EGD operates under a reasonable and stable regulatory system. In 2014, the Company began its five-year customized Incentive Regulation (IR) period through 2018. Higher return on equity (ROE) was allowed in 2014 and 2015 (compared with prior years), while forecast risk is mitigated meaningfully by the Company's having the ability to file annual updates on volume, capital cost and debt expenses. EGD can pass on to customers 100% of natural gas costs with quarterly adjustments. (2) EGD's franchise area, primarily the GTA, is viewed as one of the most economically strong service areas in Canada. In addition, the Company's large customer base of over two million should provide it with the critical mass to achieve or exceed the approved ROE over the five-year customized IR term (2014–2018) under normalized weather. However, the short-term challenge faced by the Company will be project risk management associated with the GTA Project (DBRS recognizes that Enbridge Inc. has a good track record in building pipeline projects in time and Continued on P.2

Financial Information

	For the year ended December 31				
(CA$ millions)	2014	2013	2012	2011	2010
Net income before extra. items	246	217	119	171	193
Cash flow from operations	549	524	472	473	467
Total debt in capital structure 1	60.9%	55.5%	55.5%	55.1%	58.7%
EBIT interest coverage (times)	2.37	2.58	2.05	2.29	2.62
Adjusted EBIT interest coverage (times) 2	2.61	2.85	2.30	2.55	2.86
Cash flow/Total debt 1	12.8%	16.4%	15.8%	16.0%	16.9%
Approved ROE (Ontario)	9.36%	8.93%	8.39%	8.39%	8.39%

1 Excludes inter-company subordinated loans. 2 Includes preferred dividends from IPL (less of interest expense).
Note: Reported under U.S. GAAP except 2010, which was under Canadian GAAP.

Issuer Description

Enbridge Gas Distribution Inc. (EGD) is a regulated natural gas distribution utility serving over two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. EGD also distributes natural gas to approximately 16,000 customers in northern New York State through a wholly owned subsidiary, St. Lawrence Gas Company, Inc. EGD also provides transportation services (regulated) and storage services (regulated and unregulated).

EGD is an indirect wholly owned subsidiary of Enbridge Inc.

Rating Update (CONTINUED)

within budget). Any significant cost overruns or lengthy delays would face serious regulatory review after the current IR period, with no assurance that the regulator will allow EGD to recover such costs. In addition, EGD faces a regulatory lag associated with natural gas cost recovery, which could be up to two years (instead of a normal 12-month period) should natural gas prices increase significantly above the approved costs included in rates (such as Q1 2014). In this situation, continual liquidity support from the parent (Enbridge Inc.) is required.

EGD's credit metrics in 2014 remained consistent with its current ratings. However, in 2014, the Company had modestly higher leverage and lower cash flow metrics than in 2013 as a result of an increase in short-term debt to finance higher working capital needs. The increase in working capital was the result of higher inventory and gas prices during the 2014 winter and was financed with $204 million from EGD's affiliates (including Enbridge Inc., its parent) and its revolving facility. This short-term debt increase is expected to be paid down over the next 12 months as the Company recovers the extra gas costs from customers (approved by the regulator). In 2015, financing the large free cash flow deficit caused by the $1.0 billion expected capex is critical. DBRS expects (1) the parent to continue to inject equity to fund the equity portion of the GTA Project and (2) for EGD to maintain debt leverage within the regulatory capital structure. Should EGD's credit metrics weaken significantly from their current level, a negative rating action could occur.

Rating Considerations

Strengths

1. Stable regulatory framework.
The regulatory framework in Ontario and the nature of the Company's natural gas distribution, transportation and storage operations, which are mostly regulated, have underpinned the Company's strong business risk profile. The Ontario regulatory regime provides the Company with the following benefits that support the current rating: (a) Gas supply costs are passed through to customers, with quarterly adjustments to rates, subject to regulatory review; (b) The customized IR plan (2014-2018) provides EGD with the opportunity to earn the allowed ROE through its operational efficiency, with any over-earnings that exceed the allowed ROE for the year to be shared equally with ratepayers. Forecast risk during this customized IR period is mitigated through annual updates on volumes, capital cost, demand-side management as well as pension and post-retirement benefits (which are passed through to ratepayers).

2. Strong franchise with a large customer base.
EGD is the largest regulated natural gas distributor in Canada, serving over two million customers (2.098 million active customers at the end of 2014) in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong, and its large customer base provides it with the size and scale unavailable to smaller distributors to contain operating costs during its 2014-2018 customized IR period.

3. Reasonable balance sheet and solid credit metrics.
EGD maintains a reasonable balance sheet and solid credit metrics that have been consistently in line with the current ratings. EGD is committed to maintaining its capital structure within the regulatory approved level of 64% debt and 36% equity. The current debt leverage (61% at the end of 2014) provides the Company with some financial flexibility with respect to its 2015 financing plan for the GTA Project.

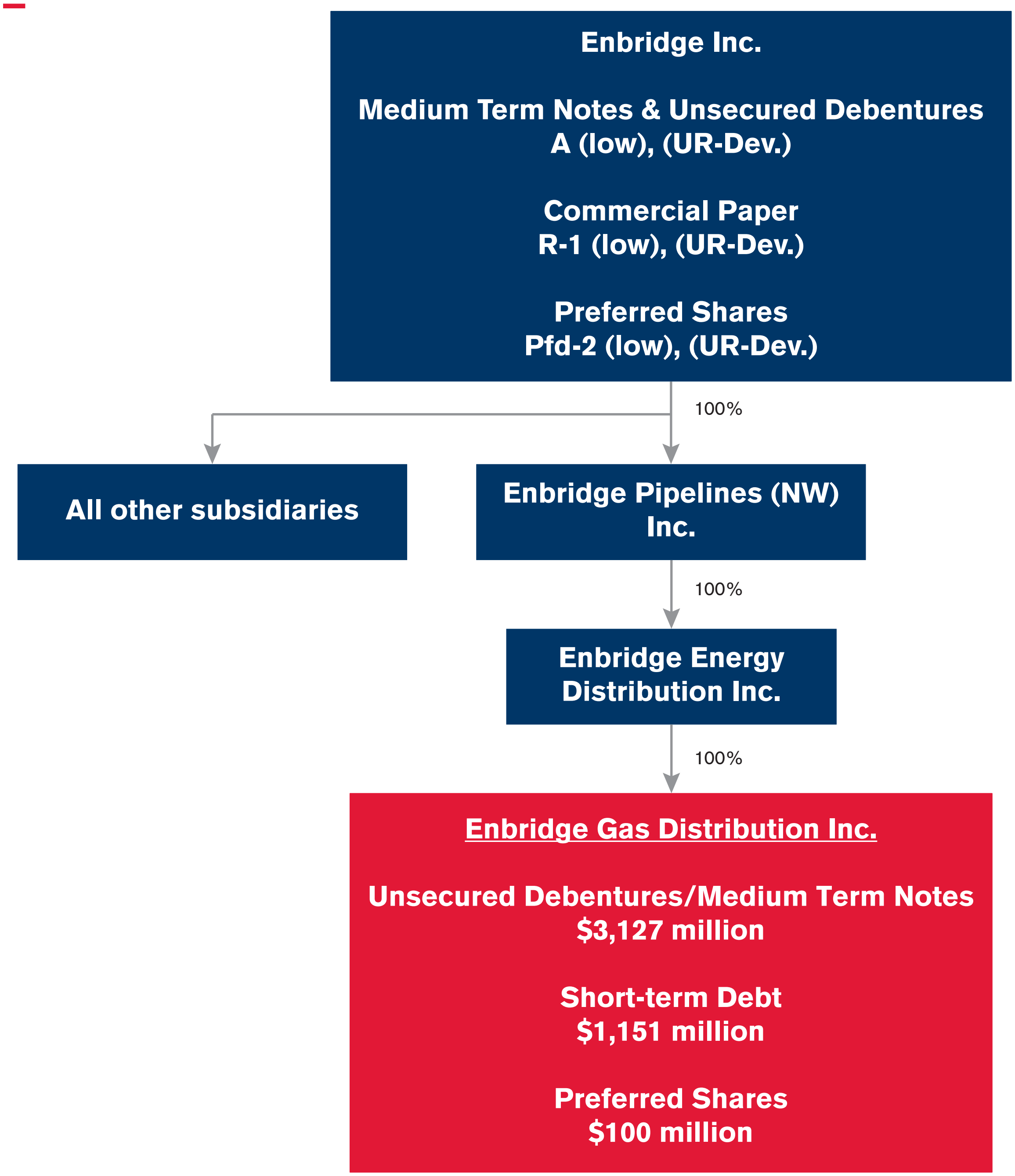
Challenges

1. Large capex program.
The Company has a large capex program, with an estimate of $1.0 billion for 2015 (annual capex in recent years has averaged approximately $527 million). This large capex reflects the following factors: (a) high capex spending is required for system improvements and upgrades and (b) the financing of the 2015 portion of the GTA Project (see the GTA Project below). As a result, EGD is expected to generate large free cash flow deficits and will require external funds. The rating confirmation incorporates DBRS's expectation that EGD will maintain its debt leverage within the regulatory approved level (64% debt) and to maintain all other metrics within the DBRS "A" rating range while carrying out its financing plan.

2. Weather-related volume risk.
Weather risk remains significant as forecast volumes (based on normalized weather) are built into the Company's base rates, while actual usage varies with actual weather; therefore, colder-than-normal weather in any given year generally results in higher earnings while the reverse is true for periods of warmer-than-normal weather. Normalized weather is, however, updated annually throughout the customized IR period by incorporating the most recent weather trend, thus mitigating any significant sustained exposure to weather conditions.

3. Managing operating costs.
EGD is in the second year of the five-year IR period. Managing its operating costs is critical for the Company to achieve or exceed allowed ROE. Earnings below the allowed ROE will not be recovered from the customers until it is 300 basis points (bps) below the allowed ROE. In that situation, the Company can request a regulatory review.

Simplified Organizational Chart



Debt information as of December 31, 2014.

The Great Toronto Area Expansion Project (the GTA Project)

- The purpose of the GTA Project is to expand EGD's natural gas distribution system in the GTA to meet the demands of customer growth and to continue delivering safe and reliable natural gas to current and future customers.
- The GTA Project will consist of two new segments of pipeline and related facilities to upgrade the existing system that delivers natural gas to several municipalities in the GTA.
- In January 2014, the Ontario Energy Board (OEB) approved the project with the estimated capital cost of approximately $756 million. Construction started in January 2015, with completion targeted by the end of 2015. The expenditure spending to date was approximately $200 million.
- The Company is expected to fund this project with cash flow from operations, equity injection from the parent and its new debt issuance. The funding will be subject to maintaining the debt leverage within the regulatory capital structure.

Earnings and Outlook

	For the year ended December 31				
(CA$ millions)	**2014**	**2013**	**2012**	**2011**	**2010**
Net gas distribution revenue	757	741	640	584	605
Gas transportation service revenue	305	328	345	421	390
Gas distribution margin	**1,062**	**1,069**	**985**	**1,005**	**995**
Other revenue 1	92	97	113	103	108
Net revenue, excluding natural gas costs	**1,154**	**1,166**	**1,098**	**1,108**	**1,103**
EBITDA	661	670	609	630	666
EBIT	375	366	289	328	396
Earnings sharing	12	0	10	13	19
Intercompany dividend income	66	65	63	63	63
Interest expense (external)	(158)	(142)	(141)	(143)	(151)
Interest expense (intercompany)	(29)	(27)	(27)	(27)	(27)
Net income before extra. items	246	217	119	171	193
Extra items	0	0	93	2	0
Reported net income	**246**	**217**	**212**	**173**	**193**

1 Adjusted for $89 million recognition in regulatory asset related to other postretirement benefits in 2012.
Note: Reported under U.S. GAAP except 2010, which was under Canadian GAAP.

Deemed equity (EGD)	36%	36%	36%	36%	36%
Approved ROE (EGD)	9.36%	8.93%	8.39%	8.39%	8.39%
Distribution rate base (CA$ millions)	4,421	4,162	4,011	3,957	3,838

Summary

- Overall: Higher net earnings in 2014 primarily reflected the following factors: (1) higher approved ROE, (2) colder weather in Ontario, (3) modest customer growth and (4) $12 million in earnings sharing with ratepayers that did not occur in 2013.
- The positive impact of the above items was partially offset by: (1) slightly lower distribution rates in 2014, (2) lower "other revenue" because of the OEB rate order and settlement allowing for recognition of regulatory assets in the prior year and (3) higher interest expense caused by higher debt.
- Net gas distribution revenue (excluding the natural gas cost) represents EGD's distribution margin earnings that are mainly generated from natural gas distribution operations. Weather, allowed ROE and customer growth were major factors that affected earnings for the year.
- Gas transportation service revenue has declined over the past three years, reflecting an eroding customer base caused by customer switches. By the end of 2014, the number of active customers was 210,815 (versus 364,027 in 2011).
- Other revenue includes largely storage revenue and other revenue arising from the OEB order and settlement.
- Dividend income represents the cash income from EGD's $825 million investment in its affiliate (IPL System Inc. (IPL)), the holder of the Company's $375 million intercompany loan outstanding at December 31, 2014. Interest expense on this loan was $29 million in 2014 ($27 million in 2013).

Outlook

- The earnings outlook for 2015 is expected to be positive, given the cold weather conditions in Q1 2015 and the continuation of customer growth in the GTA. Good operational efficiency is expected to be achieved given the Company's size and scale.
- Should the GTA Project be brought into service on time (expected by the end of 2015) and within the approved budget, earnings beyond 2015 are expected to increase meaningfully.

Financial Profile

	For the year ended December 31				
(CA$ millions)	2014	2013	2012	2011	2010
Net income before extra. items	246	217	119	171	193
Depreciation & amortization	286	304	320	302	270
Deferred income taxes/Other	17	3	33	0	4
Cash flow from operations	**549**	**524**	**472**	**473**	**467**
Dividends paid	(205)	(202)	(208)	(220)	(210)
Capex	(637)	(553)	(452)	(448)	(365)
Free cash flow before WC	**(293)**	**(231)**	**(188)**	**(195)**	**(108)**
Changes in working capital (WC)	(962)	(86)	71	15	45
Net free cash flow	**(1,255)**	**(317)**	**(117)**	**(180)**	**(63)**
Acquisitions	0	0	0	0	0
Assets sales/Divestitures	0	0	72	0	0
Net changes in equity	150	150	0	0	0
Net changes in debt	1,088	192	38	164	58
Other	8	16	1	12	(2)
Change in cash	**(9)**	**41**	**(6)**	**(4)**	**(7)**
Total debt	4,278	3,192	2,988	2,950	2,766
Total debt/Capital [1]	60.9%	55.5%	55.5%	55.1%	58.7%
EBIT interest coverage (times)	2.37	2.58	2.05	2.29	2.62
Adjusted EBIT interest coverage (times) [2]	2.61	2.85	2.30	2.55	2.86
Cash flow/Total debt [1]	12.8%	16.4%	15.8%	16.0%	16.9%
Dividends/Cash flow	37.3%	38.5%	44.1%	46.5%	45.0%
Dividend payout ratio	83.3%	93.1%	174.8%	128.7%	108.8%

1 Excludes inter-company subordinated loans.
2 Includes preferred dividends from IPL (less of interest expense on subordinated loans from IPL).
Note: Reported under U.S. GAAP except 2010, which was under Canadian GAAP.

Summary

- EGD maintained a reasonable financial profile for the current rating category in 2014, although its key credit metrics declined slightly from the prior year because of:
  - Increased debt levels to finance working capital requirements caused by higher gas inventory and gas prices. DBRS recognizes that a significant amount of this increase is short-term debt, borrowed from EGD's revolving facility and affiliate ($204 million). A substantial portion of this amount is expected to be paid down as the Company recovers from customers the variance of the actual gas cost and the gas cost embedded in rates over the next 12 months.
  - Approximately $293 million in free cash flow deficit (excluding working capital) due to increased capex for the year.
- Higher capex in 2014 was largely attributed to higher spending on the GTA Project and system improvements and upgrades as well as customer growth projects (including the Franklin County Expansion Project (Franklin Project) in New York State).
- The dividend policy in 2014 remained almost unchanged from previous years in the absolute term, but the payout as a percentage of net income was lower than the Company's target payout ratio of 90% to 100%. DBRS notes that the payout is subject to maintaining the regulatory capital structure.

Outlook

- Capex for 2015 is estimated to be approximately $1.0 billion for capital projects and maintenance. This amount is much higher than the past three-year average of $547 million. This increase largely reflects the 2015 portion of capex spending on the GTA Project.
- As a result, the Company is expected to generate a large free cash flow deficit in 2015, which is expected to be funded with new debt and equity injections from the parent. DBRS expects the parent to continue injecting equity into EGD, as it has in the past, to maintain the Company's capital structure within the regulatory approved level and within DBRS's "A" rating guidelines for a gas distribution company.

Liquidity and Long-Term Debt Maturities

Bank Lines/Liquidity (As at Dec. 31, 2014)

(CA$ millions)	Total Facilities	Drawn 1	Available	Maturity
Revolving term credit facility	1,000	935	65	Jul-16
Revolving credit facility from Enbridge Inc.	300	175	125	Jun-16
Committed line of credit*	8	8	0	2019
Uncommitted line of credit*	6	4	2	N/A
Total	**1,314**	**1,122**	**192**	

* The committed and uncommitted line of credit is at St. Lawrence Gas Company, Inc.
1 Includes commercial paper issuances, net of discount, that are backed by the $1.0 billion Revolving Term Credit Facility.

- EGD requires relatively high liquidity to finance its volatile and seasonal working capital needs, which are heavily influenced by natural gas prices and the weather. For example, the difference between the actual cost and the approved cost of natural gas reflected in rates was $673 million as at December 31, 2014. This amount requires financing until it is recovered from the customers.
- In May 2014, the OEB approved EGD's collection of a portion of the $568 million balance as at June 30, 2014, over a 24-month period beginning July 1, 2014.
- At the end of 2014, short-term debt increased significantly (by $758 million) to fund working capital needs because of colder-than-normal weather and higher natural gas prices (accounts receivable increased by $483 million and gas inventories increased by $181 million). The increase in accounts receivable will be recovered through rates within 12 months.
- The increase in short-term debt was financed with $204 million in intercompany short-term borrowings and the remainder from the revolving credit facility.
- In June 2014, in support of its working capital needs, the Company obtained a new $300 million revolving credit facility from Enbridge Inc., maturing in June 2016. As at December 31, 2014, $175 million was drawn on this facility.
- The Company's current CP program is $1.0 billion, which is fully backed by the $1.0 billion revolving term credit facility (unsecured) maturing in July 2016. As at December 31, 2014, approximately $935 million was outstanding.
- Currently, with the support of the parent, DBRS believes that EGD has sufficient liquidity to fund its working capital needs; however, any combination of cold weather and high gas prices in the future could exhaust the Company's available liquidity. Should that event occur, the parent is expected to provide further liquidity support in a timely manner for EGD.

Long-term Debt Maturity (As at Dec. 31, 2014)

(CA$ million)	2015	2016	2017	2018	2019	Thereafter	Total
Medium-term notes	2	2	502	1	1	2,619	3,127

- The Company has no refinancing need until 2017 when $502 million of the MTNs will be due. The refinancing risk in 2017 is manageable for EGD given its strong credit quality.
- EGD is subject to an EBIT-interest covenant of two times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
  - The covenant does not apply to debt issuances for debt refinancing.
  - The Company was in compliance with the test at the end of 2014.

Intercompany Subordinated Loans

- As of December 31, 2014, EGD owned $825 million of Class D, non-voting, redeemable, retractable preferred shares of IPL, which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans ($200 million due in 2049 and $175 million due in 2051), which is deeply subordinated to the debentures and MTNs. EGD is able to defer interest payments on the loans for up to five years and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company. The default of the subordinated loans cannot trigger a default of senior debt.
- Investment income in the form of dividends from IPL is approximately $66 million in 2014 whereas the interest expense on the subordinated loans from IPL was approximately $29 million.
- DBRS excludes the subordinated loans from its calculation of the Company's capital structure.
- EGD's preferred share rating was downgraded to Pfd-2 (low) from Pfd-2 in June 2001. This rating adjustment was technical in nature, reflecting the issuance of the higher-ranking intercompany subordinated loans, and was not related to any change in DBRS's outlook for the Company.

Regulation Update

Gas Distribution: Ontario

In 2013, the Company's rates were set based on the 2013 settlement relating to the cost-of-service (COS) rate application. In July 2014, the OEB rendered a decision on the Company's 2014-2018 customized IR application, with a subsequent decision and rate order provided in August 2014. The decision also approved final 2014 allowed revenues and rates with a ROE of 9.36% based on a 36% deemed common equity component of rate base. The key features of the customized IR plan include the following:

1. ***Annual allowed revenue updates for selected items that reduce forecast risk:***
   - Volumes to reflect updated customer conditions, contract market volumes and average use.
   - The customer care, demand-side management, pension and other post-employment benefits to be updated annually and to be treated as pass-through amounts from other approved mechanisms.
   - The cost of capital to be updated annually.
   - ROE to be updated using the OEB-approved parameters (using a formula).

2. ***Earning sharing:*** To the extent that the Company's actual return on the approved equity level represented by normalized earnings (excluding the effects of weather) exceeds the approved ROE for that year, the over-earnings will be shared equally between the Company and customers; however, the customers will not share earning deficits that are below the approved ROE.

3. ***Adjustments:*** Several approved deferral and variance accounts are in place for the recovery of costs that deviate from those assumed in developing the customized IR plan. The customized IR plan also includes a z-factor mechanism for the Company to recover expenses above a defined threshold ($1.5 million within a year), to the extent that any such expenses result from new regulatory orders and/or changes in statutory obligations.

4. ***Off ramps:*** An OEB review will be triggered if the Company's ROE on a normalized basis varies more than 300 bps (either negative or positive) relative to the approved ROE for that year. The regulatory review will determine the reasons for variance in earnings and could either result in adjustments to the customized IR plan or a return to COS regulation.

Gas Storage: Ontario

- EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers (since November 2006) within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates.

Transportation: National Energy Board

- TransCanada Pipelines Limited (TransCanada) transports approximately 69% (9.1 billion cubic metres) of the annual natural gas requirements of EGD's customers; the remainder is obtained through contracts with Alliance Pipeline Canada, Alliance Pipeline U.S. and Vector Pipeline.
- The Company has Firm Transportation (FT) contracts with TransCanada for a portion of the requirement. Effective July 2013, the National Energy Board (NEB) approved new tolls on the FT service for TransCanada. Under the new tolls, the Company is required to pay TransCanada the demand component regardless of the volume transported.
- Transportation costs are passed through to customers.

Gas Distribution: New York

- The Company owns St. Lawrence Gas Company, Inc. (SLG), which provides natural gas distribution services to 16,000 customers in New York State. SLG is regulated by the New York State Public Service Commission under COS and is viewed as relatively stable.
- The approved ROE for 2014 was 10.5% (2013: 10.5%) on a deemed equity of 50.0% (2013: 50.0%). Any earnings above 11.0% will be shared equally with ratepayers.
- SLG has no exposure to natural gas price risk as gas supply costs are adjusted annually, subject to regulatory review.
- SLG started construction on the Franklin Project in August 2012 following regulatory approval in July 2012. The total capital cost through 2018 is estimated to be USD 52 million. SLG is estimated to have spent approximately USD 48 million up December 31, 2014. The Franklin Project is expected to add 4,400 potential customers to the system.

Agreement with TransCanada

- In September 2013, EGD, Union Gas Limited and Gaz Métro Limited Partnership reached an agreement with TransCanada. The agreement intended to modify the tolling structure of TransCanada's Mainline System.
- In December 2014, the NEB substantially approved the term of the agreement through its approval of TransCanada's 2015-2020 Mainline toll application.
- Under the new toll structure, the Company has to pay TransCanada a fixed charge regardless of the volume consumed. Under the old toll structure, EGD paid a fixed charge and a variable charge, depending on the volume.
- All the transportation costs are passed through to customers.

Enbridge Gas Distribution Inc.

Balance Sheet

(CA$ millions)	2014	2013	2012		2014	2013	2012
	As at December 31				As at December 31		
Assets				**Liabilities & Equity**			
Cash & equivalents	35	44	3	S.T. borrowings	1,151	393	601
Accounts receivable	339	341	324	Current portion of LT debt	2	400	0
Inventories	563	382	341	Accounts payable	245	207	195
Regulatory assets	567	54	21	Operating accrued liabilities	365	329	279
Prepaid expenses & others	283	311	260	Regulatory liabilities	233	76	121
				Others	131	157	135
Total Current Assets	**1,787**	**1,132**	**949**	**Total Current Liabilities**	**2,127**	**1,562**	**1,331**
Net fixed assets	6,268	5,869	5,532	Long-term (LT) debt	3,125	2,399	2,387
Future income tax assets	8	1	0	Deferred income taxes	463	395	362
Goodwill & intangibles	161	174	177	Inter-company subordinated loans	375	375	375
Investments in affiliates	825	825	825	Other LT liabilities	943	1,026	1,094
Regulatory assets	711	312	414	Preferred shares	100	100	100
Deferred and others	19	66	18	Shareholders equity	2,646	2,522	2,266
Total Assets	**9,779**	**8,379**	**7,915**	**Total Liab. & SE**	**9,779**	**8,379**	**7,915**

	For the year ended December 31				
	2014	2013	2012	2011	2010
Balance Sheet & Liquidity & Capital Ratios					
Current ratio (times)	0.84	0.72	0.71	0.82	0.90
Cash flow/Capex (times)	0.86	0.95	1.04	1.06	1.28
(Cash flow - Dividends)/Capex (times)	0.54	0.58	0.58	0.56	0.70
Dividend payout ratio	83.3%	93.1%	174.8%	128.7%	108.8%
Dividends/Cash flow	37.3%	38.5%	44.1%	46.5%	45.0%
Profitability Ratios					
EBITDA margin	57.3%	57.5%	55.5%	56.9%	60.4%
EBIT margin	32.5%	31.4%	26.3%	29.6%	35.9%
Profit margin	21.3%	18.6%	10.8%	15.4%	17.5%
Return on equity	9.2%	8.7%	5.0%	N/A	9.9%
Return on capital	5.9%	5.9%	4.3%	N/A	6.3%
Allowed ROE (EGD)	9.36%	8.93%	8.39%	8.39%	8.39%
Allowed ROE (St. Lawrence)	10.5%	10.5%	10.5%	10.5%	N/A
Key Credit Metrics					
Cash flow/Total debt 1	12.8%	16.4%	15.8%	16.0%	16.9%
Total debt/Capital 1	60.9%	55.5%	55.5%	55.1%	58.7%
EBITDA gross interest coverage (times)	4.18	4.72	4.32	4.41	4.41
EBIT gross interest coverage (times)	2.37	2.58	2.05	2.29	2.62
Adjusted EBIT interest coverage (times) 2	2.61	2.85	2.30	2.55	2.86

1 Excludes inter-company subordinated loans.
2 Includes preferred dividends from IPL (less of interest expense on subordinated loans from IPL).
Note: Reported under U.S. GAAP except 2010, which was under Canadian GAAP.

Rating History

	Current	2014	2013	2012	2011	2010	2009
Issuer Rating	A	A	A	A	NR	NR	NR
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

Previous Report

- Enbridge Gas Distribution Inc., Rating Report, March 12, 2014.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Rating Report

Enbridge Gas Distribution Inc.

DBRS

Insight beyond the rating.

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating Update

On March 18, 2016, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debentures & Medium-Term Notes rating of Enbridge Gas Distribution Inc. (EGD or the Company) at "A," as well as its Commercial Paper rating at R-1 (low) and its Cum. & Cum. Redeemable Convertible Preferred Shares at Pfd-2 (low). All trends are Stable. The rating confirmations reflect DBRS's view that the Company's business risk profile remains strong, underpinned by its strong service area, large customer base and reasonable customized Incentive Regulation (IR) plan from 2014 through 2018. The risk associated with the Greater Toronto Area Expansion Project (the GTA Project) has also been substantially reduced by the end of 2015, as it is close to completion. The confirmations and the Stable trends reflect EGD's good financial profile with solid credit metrics and reasonable liquidity.

DBRS views the Company's five-year customized IR as supportive of the current rating. EGD has the ability to file annual updates on volume and debt expenses, thereby significantly reducing forecast errors. Allowed return on equity (ROE) for 2016 is 9.19%. Although this is lower than the ROE of 9.30% in 2015, it remains higher than the ROE that is allowed for gas distribution in other Canadian jurisdictions. Fuel costs for EGD are additionally passed through to customers and adjusted quarterly. The Company has filed its 2016 rate application and the decision is expected to be issued in Q2 2016. DBRS does not expect the decision to have any material impact on EGD's earnings.

In January 2015, the Company began construction on the GTA Project, which will extend the distribution system to service the growing population in the GTA. The cost was initially estimated at $700 million, with the final cost estimated at $930 million. Cost overruns are not expected to be added to the rate base until the next re-basing year in 2019, exposing EGD to regulatory lags; however, DBRS considers this risk to be manageable with the Company's reasonable liquidity and good balance sheet. The GTA Project is expected to be completed by the end of Q1 2016. During this build-out, EGD's credit metrics have remained supportive of the current ratings. As the financing of the GTA Project is largely completed, DBRS does not expect any material change in credit metrics over the near to medium term.

Continued on P.2

Financial Information

Enbridge Gas Distribution Inc.

	For the year ended December 31				
(CA$ millions)	2015	2014	2013	2012	2011
Cash flow/Total debt 1	13.1%	12.8%	16.4%	15.8%	16.0%
Total debt in capital structure 1	59.5%	60.9%	55.5%	55.5%	55.1%
EBIT interest coverage (times)	2.26	2.37	2.58	2.05	2.29
Adjusted EBIT interest coverage (times) 2	2.52	2.61	2.85	2.30	2.55
Cash flow from operations	569	549	524	472	473
Approved ROE (Ontario)	9.30%	9.36%	8.93%	8.39%	8.39%

1 Excludes inter-company subordinated loans. 2 Includes preferred dividends from IPL (less of interest expense on subordinated loans from IPL).

Issuer Description

EGD is a regulated natural gas distribution utility, serving over two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. EGD also distributes natural gas to approximately 16,000 customers in northern New York State through a wholly owned subsidiary, St. Lawrence Gas Company, Inc., and provides transportation services (regulated) and storage services (regulated and unregulated). EGD is an indirect wholly owned subsidiary of Enbridge Inc.

Rating Update (CONTINUED)

The Company has also maintained reasonable liquidity through the end of 2015, reflecting (1) over $700 million in undrawn facilities, (2) minimal long-term debt due in 2016 and (3) stable cash flow from operations.

Rating Considerations

Strengths

1. Supportive regulatory framework

The regulatory framework in Ontario and the nature of the Company's natural gas distribution, transportation and storage operations, which are mostly regulated, underpin the Company's strong business risk profile. The regulatory regime in Ontario provides the Company with the following benefits that support the current rating: (a) gas supply costs are passed through to customers, with quarterly adjustments to rates, subject to regulatory review; and (b) the customized IR plan (2014–2018) provides EGD the opportunity to earn the allowed ROE through operational efficiency, with the excess of the allowed ROE for the year to be shared equally with ratepayers. Forecast risk during this customized IR period is partially mitigated through annual updates on volumes, demand-side management (DSM), and pension and postretirement benefits (which are passed through to ratepayers).

2. Strong franchise with a large customer base

EGD is the largest regulated natural gas distributor in Canada, serving over 2.1 million active customers at the end of 2015 in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong compared to other service areas in Canada. EGD's large customer base provides it with the size and scale, unavailable to smaller distributors, to operate efficiently. This is very important during its 2014–2018 customized IR period.

3. Reasonable balance sheet and solid credit metrics

EGD maintains a reasonable balance sheet and solid credit metrics that have been consistent with the current ratings. EGD is committed to maintaining its capital structure within the regulatory capital structure of 64% debt and 36% equity.

Challenges

1. Weather-related volume risk

Weather risk remains significant as forecast volumes (based on normalized weather) are built into the Company's base rates, while actual usage varies with actual weather. Therefore, colder-than-normal weather in any given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. However, normalized weather is updated annually throughout the customized IR period by incorporating the most recent weather trend, thus mitigating any significant sustained exposure to weather conditions.

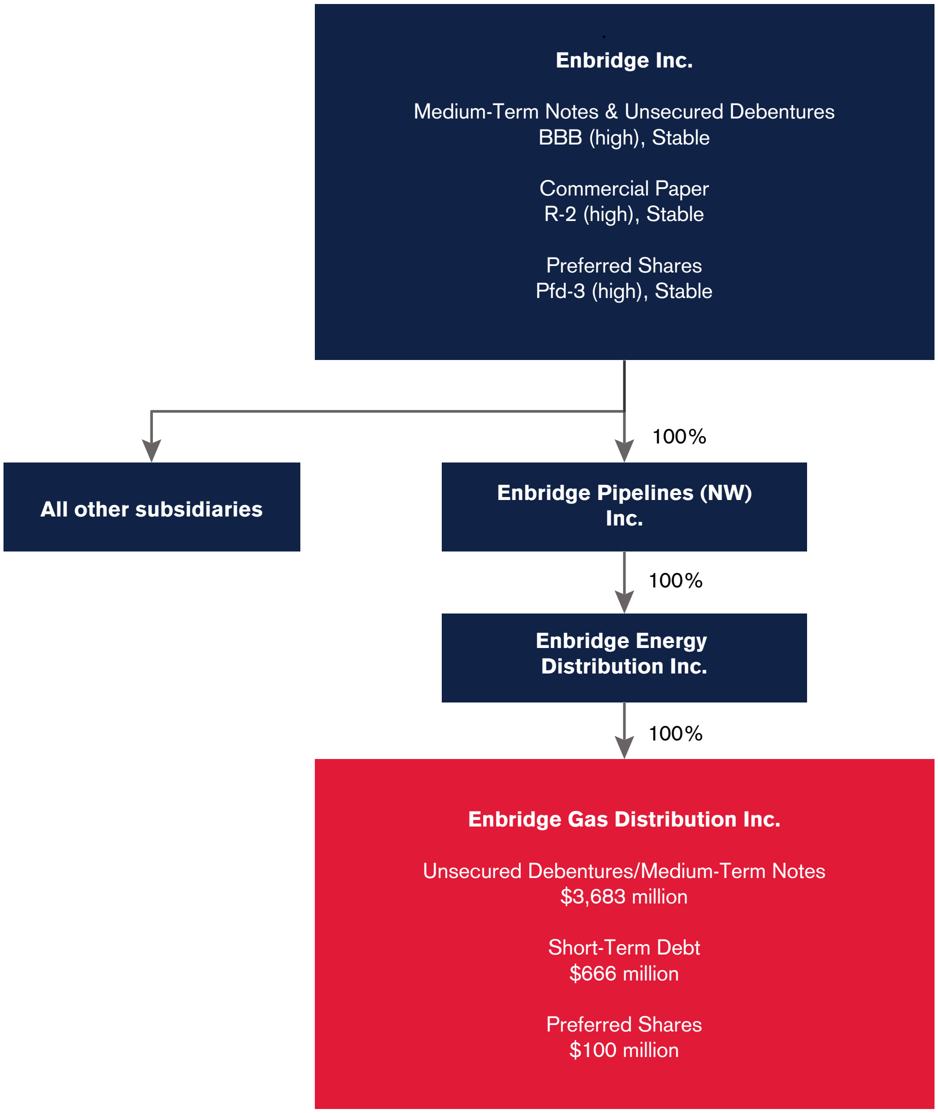
2. Managing operating costs under Incentive Regulation

EGD is in the midst of its five-year customized IR period. Managing operating costs is critical for the Company to achieve or exceed the allowed ROE. Earnings below the allowed ROE will not be recovered from customers unless actual ROE is 300 basis points below the allowed ROE, at which point the Company can request a regulatory review.

3. Potential regulatory lag

EGD faces potential regulatory lag with respect to the recovery of natural gas costs. Although the Company is allowed to pass on to the customer all natural gas costs with quarterly adjustments, the potential regulatory lag still exists. In the event that natural gas costs increase substantially within a short period of time, the Company may have to recover such costs over a longer time frame than it normally does. In addition, the cost overruns associated with the GTA project is not expected to be added to the rate base until the Company's rebasing in 2019.

Simplified Organizational Chart



Note: Debt information as of December 31, 2015.

The Great Toronto Area Expansion Project (the GTA Project)

- The purpose of the GTA Project is to expand EGD's natural gas distribution system in the GTA to meet the demands of customer growth and to continue delivering safe and reliable natural gas to current and future customers.
- The GTA Project will consist of two new segments of pipelines and related facilities to upgrade the existing system that delivers natural gas to several municipalities within the GTA.
- In January 2014, the Ontario Energy Board (OEB) approved the project with an estimate capital cost of approximately $756 million. Construction started in January 2015, with completion targeted by the end of 2015. The schedule and cost of the GTA Project were updated in the third quarter of 2015, with the updated cost to be approximately $930 and to be completed by March–April 2016 due to the complexity of the construction and the requirements from government and permitting agencies. Total spending on the GTA Project was approximately $750 million at the end of 2015.
- The Company funded this project with a mixture of cash flow from operations, equity injection from the parent and a new debt issuance. The funding is subject to maintaining the debt leverage within the regulatory capital structure.

Earnings and Outlook

Enbridge Gas Distribution Inc.

(CA$ millions)	2015	2014	2013	2012	2011
	For the year ended December 31				
Gas distribution revenue	3,043	2,803	2,221	1,869	1,880
Gas transportation service revenue	344	305	328	345	421
Gas commodity and distribution costs	(2,322)	(2,046)	(1,480)	(1,229)	(1,296)
Gas distribution margin	**1,065**	**1,062**	**1,069**	**985**	**1,005**
Other revenue 1	97	92	97	113	103
Net revenue, excluding natural gas costs	**1,162**	**1,154**	**1,166**	**1,098**	**1,108**
EBITDA	665	661	670	609	630
EBIT	375	375	366	289	328
Earnings sharing	(7)	(12)	0	(10)	(13)
Other income 2	66	66	65	63	63
Interest expense (external)	(166)	(158)	(142)	(141)	(143)
Interest expense (intercompany)	(27)	(29)	(27)	(27)	(27)
Net income before extra. items	242	246	217	119	171
Extra items	(8)	0	0	93	2
Reported net income	234	246	217	212	173

1 Adjusted for $89 million recognition in regulatory asset related to other postretirement benefits in 2012. 2 Includes $63 million intercompany dividend income.

	2015	2014	2013	2012	2011
Deemed equity (EGD)	36%	36%	36%	36%	36%
Approved ROE (EGD)	9.30%	9.36%	8.93%	8.39%	8.39%
Distribution rate base (EGD) (CA$ millions)	4,957	4,421	4,162	4,011	3,957

2015 Summary

- Net income: EGD's net earnings before non-recurring items was in line with 2014 due to the following factors: (1) high gas distribution margins due to higher distribution charges and modest customer growth, (2) higher other revenue from higher pipeline and storage optimization sales and higher DSM incentive revenue, offset by (3) higher operating cost and higher depreciation cost due to the growing asset base.
- Earnings sharing, which reflects extra earnings above the allowed regulated earnings that would have to be shared with ratepayers, was lower in 2015.
- Non-recurring items reflected one-time severance costs and gain of asset sales incurred in 2015.
- Dividend Income represents the cash income from EGD's $825 million investment in its affiliate (IPL System Inc.), the holder of the Company's $375 million inter-company loan outstanding as at December 31, 2015. Interest expense on this loan was $27 million in 2015.
- Gas transportation service revenue represents services charged to customers who do not purchase natural gas from EGD.

2016 Outlook

- Assuming normal weather conditions, the earnings outlook for 2016 is modestly positive. This is due to the modestly higher earnings expected from continued growth in the rate base, especially due to the GTA Project. The expected increase is expected to be partially offset by a lower ROE (9.19% in 2016 versus 9.30% in 2015). Good operational efficiency is expected to be achieved, given the Company's size and scale.

Financial Profile

Enbridge Gas Distribution Inc.

(CA$ millions)	For the year ended December 31 2015	2014	2013	2012	2011
Net income before extra. items	242	246	217	119	171
Depreciation & amortization	290	286	304	320	302
Deferred income taxes/Other	37	17	3	33	0
Cash flow from operations	**569**	**549**	**524**	**472**	**473**
Dividends paid	(220)	(205)	(202)	(208)	(220)
Capex	(1,023)	(637)	(553)	(452)	(448)
Free cash flow before WC	**(674)**	**(293)**	**(231)**	**(188)**	**(195)**
Changes in working capital (WC)	325	(1,031)	(86)	71	15
Changes in regulatory assets & liabilities	(52)	52	0	0	0
Net free cash flow	**(401)**	**(1,272)**	**(317)**	**(117)**	**(180)**
Dispositions/(Acquisitions)	8	0	0	72	0
Other investing activities	151	17	6	(11)	5
Net changes in equity	200	150	150	0	0
Net changes in debt	64	1,091	180	38	164
Other	(3)	(2)	10	12	7
Change in cash	**19**	**(16)**	**29**	**(6)**	**(4)**
Total debt	4,349	4,278	3,192	2,988	2,950
Total debt/Capital 1	59.5%	60.9%	55.5%	55.5%	55.1%
EBIT interest coverage (times)	2.26	2.37	2.58	2.05	2.29
Adjusted EBIT interest coverage (times) 2	2.52	2.61	2.85	2.30	2.55
Cash flow/Total debt 1	13.1%	12.8%	16.4%	15.8%	16.0%
Dividends/Cash flow	38.7%	37.3%	38.5%	44.1%	46.5%
Dividend payout ratio	90.9%	83.3%	93.1%	174.8%	128.7%

1 Excludes inter-company subordinated loans. 2 Includes preferred dividends from IPL (less of interest expense on subordinated loans from IPL).

2015 Summary

- EGD's credit metrics remained consistent with the current rating category in 2015.
- The debt-to-capital ratio remains higher than 2013 due to debt issued to finance the GTA Project. However, leverage of 60% continues to be in line with DBRS's "A" rating category.
- The Company generated an approximately $675 million free cash flow deficit (excluding working capital) due to high capex for the GTA Project.
- The dividend policy in 2015 remained relatively high at the targeted payout ratio of 90% to 100% of core net income. At this ratio, the regulatory capital structure should still be maintained.

2016 Outlook

- Given the estimated capex for 2016 of $700 million, DBRS estimates the Company's free cash flow deficit to be approximately $350 million. DBRS expects EGD to finance this deficit with a mix of debt and equity injection from its parent in a way that the debt-to-capital ratio will remain in line with the regulatory capital structure.
- Cash flow is expected to increase, reflecting the expected completion of the GTA project.

Liquidity and Long-Term Debt Maturities

Bank Lines/Liquidity

Credit Facilities As at Dec. 31, 2015

(CA$ millions)	Total Facilities	Drawn 1	Available	Maturity
Revolving term credit facility	1,000	595	405	July 2017
Revolving credit facility from Enbridge Inc.	300	0	300	May 2017
Committed line of credit *	10	8	2	2019
Uncommitted line of credit *	7	4	3	N/A
Total	1,317	607	710	

* The committed and uncommitted line of credit is at St. Lawrence Gas Company, Inc.
1 Includes commercial paper issuances, net of discount, that are backed by the $1.0 billion Revolving Term Credit Facility.

- EGD requires relatively high liquidity to finance its volatile and seasonal working capital needs, which are heavily influenced by natural gas prices and the weather.
- As of December 31, 2015, the Company's $300 million revolving credit facility from Enbridge Inc. was undrawn.
- The Company's current commercial paper program is $1.0 billion, which is fully backed by the $1.0 billion revolving term credit facility (unsecured), maturing in July 2017. As at December 31, 2015, approximately $595 million of commercial paper was outstanding.
- Currently, with the support of the parent, DBRS believes that EGD has sufficient liquidity to fund its working capital needs. However, any combination of cold weather and high gas prices in the future could exhaust the Company's available liquidity. Should that event occur, the parent is expected to continue to provide further liquidity support in a timely manner for EGD, as evidenced in winter 2014.

Debt Maturities Table

As at Dec. 31, 2015 (CA$ million)	2016	2017	2018	2019	2020	Thereafter	Total
Medium-term notes	2	502	2	2	400	2,775	3,683

- The Company has $502 million of medium-term notes due in 2017. The refinancing risk is manageable given EGD's strong credit quality.
- EGD is subject to an EBIT-interest covenant of two times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
  - The covenant does not apply to debt issuances for debt refinancing.
  - The Company was in compliance with the covenant at the end of 2015.

Inter-Company Subordinated Loans

- As of December 31, 2015, EGD owned $825 million of Class D, non-voting, redeemable, retractable preferred shares of IPL System Inc. (IPL), which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans ($200 million due in 2049 and $175 million due in 2051), which is deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years, and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company. The default of the subordinated loans cannot trigger a default of senior debt.
- Investment income in the form of dividends from IPL is approximately $63 million in 2015, whereas the interest expense on the subordinated loans from IPL was approximately $27 million.
- DBRS excludes the subordinated loans from its calculation of the Company's capital structure.

Regulation

Regulatory Update 2015–2016

Gas Distribution: Ontario

In 2013, the Company's rates were based on the 2013 settlement relating to the cost-of-service (COS) rate application. In July 2014, the OEB rendered a decision on the Company's 2014–2018 customized IR application, with a subsequent decision and rate order provided in August 2014. The decision also approved final 2014 allowed revenues and rates with an ROE of 9.36% based on a 36% deemed common equity component of rate base. The revenue requirement is updated annually based on volumes, DSM, and pension and postretirement benefits (which are passed through to ratepayers). In May 2015, the OEB approved final rates for 2015. In December 2015, OEB approved interim rates for 2016.

The key features of the customized IR plan include the following:

1. **Annual allowed revenue updates for selected items that help reduce forecast risk:**
   - Volumes to reflect updated customer conditions, contract market volumes, and average use.
   - The customer care, DSM, pension and other post-employment benefits to be updated annually and be treated as pass-through amounts from other approved mechanisms.
   - The cost of capital to be updated annually (approved ROE 9.19% in 2016), using the OEB approved parameters.
2. **Earning sharing:** To the extent the Company's actual return on the approved equity level represented by normalized earnings (excluding the effects of weather) exceeds the approved ROE for that year, the over-earnings will be shared equally between the Company and customers. However, the customers will not share earning deficits that are below the approved ROE.
3. **Adjustments:** Several approved deferral and variance accounts are in place for the recovery of costs that deviate from those assumed in developing the customized IR plan. The customized IR plan also includes a z-factor mechanism for the Company to recover expenses above a defined threshold ($1.5 million within a year), to the extent any such expenses result from new regulatory orders and/or changes in statutory obligations.
4. **Off ramps:** An OEB review will be triggered if the Company's ROE on a normalized basis varies more than 300 basis points (either negative or positive) relative to the approved ROE for that year. The regulatory review will determine the reasons for variance in earnings and could either result in adjustments to the customized IR plan or a return to COS regulation.

Gas Storage: Ontario

- EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers (since November 2006) within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates.

Transportation: National Energy Board (NEB)

- TransCanada Pipelines Limited (TransCanada) transports approximately 73% (9.2 billion cubic meters) of the annual natural gas requirements of EGD's customers. The remainder is obtained through contracts with Alliance Pipeline Canada, Alliance Pipeline U.S. and Vector Pipeline.
- The Company has Firm Transportation (FT) contracts with TransCanada for a portion of the requirement. Effective July 2013, the NEB approved new tolls on the FT service for TransCanada. Under the new tolls, the Company is required to pay TransCanada the demand component regardless of the volume transported.
- Transportation costs are passed through to customers.

Gas Distribution: New York

- The Company owns St. Lawrence Gas Company, Inc. (SLG), which provides natural gas distribution services to 16,000 customers in New York State. SLG is regulated by the New York State Public Service Commission under COS and is viewed as relatively stable.
- The approved ROE for 2015 was 10.5% (2014: 10.5%) on deemed equity of 50% (2014: 50%). Any earnings above 11% will be shared equally with ratepayers.
- SLG has no exposure to natural gas price risk, with gas supply costs being adjusted annually, subject to regulatory review.
- SLG started construction on the Franklin Project in August 2012 following regulatory approval in July 2012. The total capital cost through 2018 is estimated to be USD 52 million. SLG has spent approximately USD 51 million by the end of 2015. The Franklin Project is expected to add 4,400 potential customers to the system.

Agreement with TransCanada Pipelines Limited (TCPL)

- In September 2013, EGD, Union Gas Limited and Gaz Metro Limited Partnership reached an agreement with TCPL. The agreement was intended to modify the tolling structure of TCPL's Mainline system.
- In December 2014, the NEB substantially approved the term of the agreement through its approval of TCPL's 2015–2020 Mainline toll application.
- Under the new toll structure, the Company has to pay TCPL a fixed charge regardless of the volume consumed. Under the old toll structure, EGD paid a fixed charge and a variable charge, depending on the volume.
- All the transportation costs are passed through to customers.

Enbridge Gas Distribution Inc.

Balance Sheet (US GAAP)
(CA$ millions)

	Dec. 31				Dec. 31		
	2015	**2014**	**2013**		**2015**	**2014**	**2013**
Assets				**Liabilities & Equity**			
Cash & equivalents	36	17	44	S.T. borrowings	666	1,151	393
Accounts receivable	314	339	341	Current portion of LT debt	2	2	400
Inventories	547	563	382	Accounts payable	201	184	207
Regulatory assets	216	567	54	Operating accrued liabilities	396	351	329
Prepaid expenses & others	270	283	311	Regulatory liabilities	136	233	76
				Others	224	188	157
Total Current Assets	**1,383**	**1,769**	**1,132**	**Total Current Liabilities**	**1,625**	**2,109**	**1,562**
Net fixed assets	7,081	6,268	5,869	Long-term (LT) debt	3,681	3,125	2,399
Future income tax assets	8	8	1	Deferred income taxes	524	463	395
Goodwill & intangibles	157	161	174	Inter-company subordinated loans	375	375	375
Investments in affiliates	825	825	825	Other LT liabilities	847	943	1,026
Regulatory assets	526	711	312	Preferred shares	100	100	100
Deferred and others	22	19	66	Shareholders equity	2,850	2,646	2,522
Total Assets	**10,002**	**9,761**	**8,379**	**Total Liab. & SE**	**10,002**	**9,761**	**8,379**

Balance Sheet &
Liquidity & Capital Ratios

	For the year ended December 31				
	2015	**2014**	**2013**	**2012**	**2011**
Current ratio (times)	0.85	0.84	0.72	0.71	0.82
Cash flow/Capex (times)	0.56	0.86	0.95	1.04	1.06
(Cash flow - Dividends)/Capex (times)	0.34	0.54	0.58	0.58	0.56
Dividend payout ratio	90.9%	83.3%	93.1%	174.8%	128.7%
Dividends/Cash flow	38.7%	37.3%	38.5%	44.1%	46.5%
Profitability Ratios					
EBITDA margin	57.2%	57.3%	57.5%	55.5%	56.9%
EBIT margin	32.3%	32.5%	31.4%	26.3%	29.6%
Profit margin	20.8%	21.3%	18.6%	10.8%	15.4%
Return on equity	8.5%	9.2%	8.7%	5.0%	N/A
Return on capital	4.4%	5.0%	5.6%	4.6%	N/A
Allowed ROE (EGD)	9.30%	9.36%	8.93%	8.39%	8.39%
Allowed ROE (St. Lawrence)	10.5%	10.5%	10.5%	10.5%	10.5%
Key Credit Metrics					
Cash flow/Total debt 1	13.1%	12.8%	16.4%	15.8%	16.0%
Total debt/Capital 1	59.5%	60.9%	55.5%	55.5%	55.1%
EBITDA gross interest coverage (times)	4.01	4.18	4.72	4.32	4.41
EBIT gross interest coverage (times)	2.26	2.37	2.58	2.05	2.29
Adjusted EBIT interest coverage (times) 2	2.52	2.61	2.85	2.30	2.55
Fixed-charge coverage	2.22	2.33	2.52	2.01	2.26

1 Excludes inter-company subordinated loans. 2 Includes preferred dividends from IPL (less interest expense on subordinated loans from IPL).

Rating History

	Current	2015	2014	2013	2012
Issuer Rating	A	A	A	A	A
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

Previous Report

- Enbridge Gas Distribution Inc., Rating Report, March 18, 2015.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Rating Report

Enbridge Gas Distribution Inc.

DBRS
Insight beyond the rating.

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Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating Update

On September 8, 2016, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debentures & Medium-Term Notes rating of Enbridge Gas Distribution Inc. (EGD or the Company) at "A," as well as its Commercial Paper rating at R-1 (low) and its Cum. & Cum. Redeemable Convertible Preferred Shares at Pfd-2 (low). All trends are Stable. The confirmations were made concurrently with DBRS's decision to maintain the Under Review with Developing Implications status on all the ratings of Enbridge Inc. (ENB; rated BBB (high), UR-Dev.), the 100% owner of EGD, following the announcement that ENB had entered into an agreement to acquire Spectra Energy Corp. (SEC) in an all-share exchange transaction (the ENB-SEC Transaction; please see DBRS's ENB press release dated September 8, 2016). The confirmations of EGD's ratings reflect DBRS's view that EGD is assessed on a stand-alone basis and that its ratings are unaffected by the ENB-SEC Transaction because of the nature of its being a regulated utility and that it is strongly protected by the regulation.

The regulatory framework remains stable, as EGD is in the third year of a five-year customized Incentive Regulation (IR) plan through 2018. In May 2016, EGD received the final rate order on its 2016 rate application from the Ontario Energy Board (OEB). The decision allowed for $14 million for the recovery of revenue deficiency related to the January 2016 through June 2016 time period. This decision is viewed as positive, as it reflects the timely recovery of revenue deficiency should it arise and be deemed prudent by the OEB. Although return on equity (ROE) is lower in 2016 at 9.19% compared with 9.30% in 2015, DBRS does not expect any material impact on earnings.

From a business risk perspective, the completion of the Western and Eastern segments of the Greater Toronto Area expansion project (the GTA Project) in March 2016 significantly reduced the construction risk associated with the project. The remaining work on the GTA Project includes the installation and upgrade of two additional stations through 2017. The cost of the GTA Project is estimated to be approximately $930 million, of which approximately $845 million has been spent as of June 30, 2016.

The Company's financial profile for the 12 months to June 30, 2016, shows slightly weaker EBIT-to-interest and cash flow-to-debt ratios caused mainly by warmer weather, while the debt-to-capital ratio improved modestly mainly because of lower debt levels. However, the decrease in interest coverage and cash flow ratios are not material. Under normal weather conditions, DBRS expects these ratios to improve in 2017, as earnings and cash flow will benefit from a larger rate base with the GTA Project expected to be substantially completed in 2016. The Company's liquidity at the end of June 2016 remained solid, reflecting (1) over $465 million in undrawn facilities, (2) minimal long-term debt due in 2016 and (3) much lower capex in H2 2016 and 2017 than the 2015 to June 2016 period.

Financial Information

	6 mos. Jun. 30		12 mos. Jun. 30	Year ended December 31		
Enbridge Gas Distribution Inc.	**2016**	**2015**	**2016**	**2015**	**2014**	**2013**
Cash flow/Total debt 1	15.7%	18.8%	12.7%	13.1%	12.8%	16.4%
Total debt in capital structure 1	58.7%	57.9%	58.7%	59.5%	60.9%	55.5%
EBIT interest coverage (times)	2.67	3.20	2.02	2.26	2.37	2.58
Adjusted EBIT interest coverage (times) 2	2.89	3.49	2.26	2.52	2.61	2.85

1 Excludes inter-company subordinated loans. 2 Includes intercompany preferred dividends from IPL (less of interest expense on subordinated loans from IPL).

Issuer Description

EGD is a regulated natural gas distribution utility serving over 2.13 million customers in the central, eastern and the Niagara Peninsula regions of Ontario. EGD also distributes natural gas to approximately 16,000 customers in northern New York State through a wholly owned subsidiary, St. Lawrence Gas Company, Inc., and provides transportation services (regulated) and storage services (regulated and unregulated). EGD is an indirect wholly owned subsidiary of Enbridge Inc.

Rating Considerations

Strengths

1. Supportive regulatory framework

The regulatory framework in Ontario and the nature of the Company's natural gas distribution, transportation and storage operations, which are mostly regulated, underpin the Company's strong business risk profile. The regulatory regime in Ontario provides the Company with the following benefits that support the current rating: (a) gas supply costs are passed through to customers, with quarterly adjustments to rates, subject to regulatory review; and (b) the customized IR plan (2014–2018) provides EGD the opportunity to earn the allowed return on equity (ROE) of 9.19% in 2016 through operational efficiency, with the excess of the allowed ROE for the year to be shared equally with ratepayers. Forecast risk during this customized IR period is partially mitigated through annual updates on volumes, demand-side management (DSM) and pension and post-retirement benefits (which are passed through to ratepayers).

2. Strong franchise with a large customer base

EGD is the largest regulated natural gas distributor in Canada, serving approximately 2.13 million active customers at the end of June 2016 in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong compared with other service areas in Canada. EGD's large customer base provides it with the size and scale, unavailable to smaller distributors, to operate efficiently. This is very important during its 2014–2018 customized IR period.

3. Reasonable balance sheet and solid credit metrics

EGD maintains a reasonable balance sheet and solid credit metrics that have been consistent with the current ratings. EGD is committed to maintaining its capital structure within the regulatory capital structure of 64% debt and 36% equity. At the end of June 2016, the debt-to-capital ratio was 58.7%.

Challenges

1. Weather-related volume risk

Weather risk remains significant, as forecast volumes (based on normalized weather) are built into the Company's base rates, while actual usage varies with actual weather. Therefore, colder-than-normal weather in any given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. However, normalized weather is updated annually throughout the customized IR period by incorporating the most recent weather trend, thus mitigating any significant sustained exposure to weather conditions.

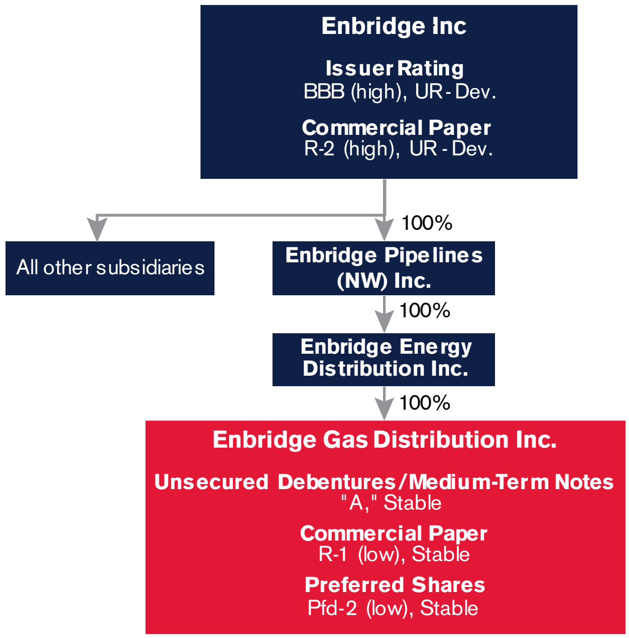
2. Managing operating costs under the Incentive Regulation

EGD is in the third year of its five-year customized IR period. Managing operating costs is critical for the Company to achieve or exceed the allowed ROE. Earnings below the allowed ROE will not be recovered from customers unless actual ROE is 300 basis points below the allowed ROE, at which point the Company can request a regulatory review.

3. Potential regulatory lag

EGD faces potential regulatory lag with respect to the recovery of natural gas costs. Although the Company is allowed to pass on to customers all natural gas costs with quarterly adjustments, potential regulatory lag still exists. In the event that natural gas costs increase substantially within a short period of time, the Company may have to recover such costs over a longer time frame than it normally does. In addition, the cost overruns associated with the GTA Project (estimated to be approximately $243 million) is not expected to be added to the rate base until the Company's rebasing in 2019.

Simplified Organizational Chart



As of September 15, 2016.

The Great Toronto Area Expansion Project (the GTA Project)

- The purpose of the GTA Project is to expand EGD's natural gas distribution system in the GTA to meet the demands of customer growth and to continue delivering safe and reliable natural gas to current and future customers.
- The GTA Project will consist of two new segments of pipelines and related facilities to upgrade the existing system that delivers natural gas to several municipalities within the GTA.
- In January 2014, the OEB approved the project with an estimated capital cost of approximately $687 million. Construction started in January 2015, with completion targeted by the end of 2015. The schedule and cost of the GTA Project were updated in the third quarter of 2015 to approximately $930 million with completion targeted for March–April 2016 because of the complexity of the construction and the requirements from government and permitting agencies. Total spending on the GTA Project was approximately $845 million at the end of June 2016.
- In March 2016, both the western and eastern segments were placed into service, with two additional stations expected to be installed and upgraded in 2017.
- The Company funded this project with a mixture of cash flow from operations, equity injection from the parent and a new debt issuance. The funding is subject to maintaining the debt leverage within the regulatory capital structure.

Earnings and Outlook

Enbridge Gas Distribution Inc.	6 mos. Jun. 30		12 mos. Jun. 30	Year ended December 31		
(CA$ millions)	2016	2015	2016	2015	2014	2013
Gas distribution revenue	1,482	2,086	2,439	3,043	2,803	2,221
Gas transportation service revenue	187	205	326	344	305	328
Gas commodity and distribution costs	(1,047)	(1,679)	(1,690)	(2,322)	(2,046)	(1,480)
Gas distribution margin	622	612	1,075	1,065	1,062	1,069
Other revenue	45	52	90	97	92	97
Net revenue, excluding natural gas costs	667	664	1,165	1,162	1,154	1,166
EBITDA	408	417	656	665	661	670
EBIT	252	269	358	375	375	366
Earnings sharing	(8)	(8)	(7)	(7)	(12)	0
Other income 1	33	37	62	66	66	65
Interest expense (external)	(94)	(84)	(177)	(166)	(158)	(142)
Interest expense (intercompany)	(13)	(15)	(26)	(27)	(29)	(27)
Net income before extra. items	164	180	226	242	246	217
Extra items	0	0	(8)	(8)	0	0
Reported net income	164	180	218	234	246	217

1 Include intercompany dividend income.

Deemed equity (EGD)	36%	36%	36%	36%	36%	36%
Approved ROE (EGD)	9.19%	9.30%	9.19%	9.30%	9.36%	8.93%
Distribution rate base (EGD) (CA$ millions)				4,957	4,421	4,162

Summary

- **2015**: EGD's EBIT remained stable compared with 2014 as a result of the following factors: (1) high gas distribution margins caused by higher distribution charges and modest customer growth, (2) higher Other revenue from higher pipeline and storage optimization sales and higher DSM incentive revenue, offset by (3) higher operating cost and slightly higher depreciation expense caused by the growing asset base.
- **H1 2016**: EBIT was slightly lower than H1 2015, reflecting the following factors: (1) warmer weather in H1 2016, (2) higher depreciation expense because of a larger rate base, partially offset by (3) higher distribution charges from growth in rate base, customer count and lower storage and transportation costs.
- Earnings sharing reflects extra earnings above the allowed regulated earnings that would have to be shared with ratepayers. In 2014, 2015 and H1 2016, actual earnings from regulated assets exceeded the allowed regulated earnings, demonstrating good performance from EGD's regulated operations.
- Non-recurring items 2015 include one-time severance costs and gain on asset sales.
- Dividend Income includes the cash income (approximately $63 million in 2015 and $31 million in H1 2016) from EGD's $825 million investment in its affiliate, IPL System Inc. (IPL), the holder of the Company's $375 million inter-company loan outstanding as at June 30, 2016. Interest expense on this loan was $27 million in 2015 ($13 million for H1 2016).
- Gas transportation service revenue represents services charged to customers who do not purchase natural gas from EGD. Lower revenue in H1 2016 compared with H1 2015 was largely due to warmer weather in H1 2016.

Outlook

- Assuming normal weather conditions, the earnings outlook for 2016 is modestly positive. This is due to the modestly higher earnings expected from continued growth in the rate base, especially related to the GTA Project, and customer growth. This increase is expected to be partially offset by a lower ROE (9.19% in 2016 versus 9.30% in 2015). Earnings sharing is expected to continue to be positive for EGD because of its operational efficiency, given the Company's size and scale.

Financial Profile

Enbridge Gas Distribution Inc.	6 mos. Jun. 30		12 mos. Jun. 30	Year ended December 31		
(CA$ millions where applicable)	2016	2015	2016	2015	2014	2013
Net income before extra. items	164	180	226	242	246	217
Depreciation & amortization	156	148	298	290	286	304
Deferred income taxes/Other	12	34	15	37	17	3
Cash flow from operations	**332**	**362**	**539**	**569**	**549**	**524**
Dividends paid	(117)	(113)	(224)	(220)	(205)	(202)
Capex	(313)	(396)	(940)	(1,023)	(637)	(553)
Free cash flow before WC	(98)	(147)	(625)	(674)	(293)	(231)
Changes in working capital (WC)	382	539	168	325	(1,031)	(86)
Changes in regulatory items/Refund	(12)	0	(64)	(52)	52	0
Net free cash flow	**272**	**392**	**(521)**	**(401)**	**(1,272)**	**(317)**
Dispositions/(Acquisitions)	0	8	0	8	0	0
Other investing activities	(100)	19	32	151	17	6
Net changes in equity	0	0	200	200	150	150
Net changes in debt	(91)	(428)	401	64	1,091	180
Other	0	0	(3)	(3)	(2)	10
Change in cash	**81**	**(9)**	**109**	**19**	**(16)**	**29**
Total debt	4,242	3,849	4,242	4,349	4,278	3,192
Total debt/Capital 1	58.7%	57.9%	58.7%	59.5%	60.9%	55.5%
EBIT interest coverage (times)	2.67	3.20	2.02	2.26	2.37	2.58
Adjusted EBIT interest coverage (times) 2	2.89	3.49	2.26	2.52	2.61	2.85
Cash flow/Total debt 1	15.7%	18.8%	12.7%	13.1%	12.8%	16.4%
Dividends/Cash flow	34.9%	30.9%	41.2%	38.7%	37.3%	38.5%
Dividend payout ratio	71.3%	62.8%	99.1%	90.9%	83.3%	93.1%

1 Excludes inter-company subordinated loans. 2 Includes preferred dividends from IPL (less of interest expense on subordinated loans from IPL).

Summary

- EGD's financial profile remained solid, with all key credit metrics in LTM 2016 supportive of the current ratings.
  - The debt-to-capital ratio of 58.7% at June 30, 2016, was lower than the regulated capital structure of 64.0% debt. This ratio was supported by $200 million in equity injection from ENB in 2015.
  - The cash flow-to-debt ratio for LTM 2016 was slightly weaker than 2015 but remained within the "A" rating range.
  - EBIT-interest coverage remained strong, supported by the low interest rate environment.
- High capex in 2015 and LTM 2016 for the GTA Project was sufficiently financed with internally generated cash flows, an equity injection from the Company's parent and new debt issuance by EGD. Financing was consistent with the Company's plan, resulting in a stable capital structure.
- The dividend payout in terms of cash flow in 2015 and H1 2016 remained relatively low at around the 40% range. The Company's policy is to pay out 100% of earnings as dividends.

Outlook

- The Company's financial profile should remain stable over the medium term based on the following DBRS expectations: (1) The estimated capex for 2017 is expected to be lower than 2015 and 2016, as the GTA Project will be substantially completed by the end of 2016. Subsequently, the free cash flow deficit is expected to be significantly reduced. (2) Cash flow is expected to increase, as the rate base should grow meaningfully following the completion of the GTA Project, positively affecting the cash flow-to-debt ratio.

Liquidity and Long-Term Debt Maturities

Bank Lines/Liquidity

Credit Facilities

As at Jun. 30, 2016

(CA$ millions)	Total Facilities	Drawn [1]	Available	Maturity
Enbridge Gas Distribution Inc.	1,000	535	465	Jul. 2018
St. Lawrence Gas Company, Inc.	17	13	4	2019
Total	**1,017**	**548**	**469**	

[1] Includes commercial paper issuances, net of discount, that are backed by the $1.0 billion Revolving Term Credit Facility.

- EGD requires relatively high liquidity to finance its volatile and seasonal working capital needs, which are heavily influenced by natural gas prices and the weather.
- The Company had a $300 million revolving credit facility with ENB, but this facility expired in May 2016 and was not renewed.
- The Company's current commercial paper program of $1.0 billion is fully backed by the $1.0 billion revolving term credit facility (unsecured), maturing in July 2018.
- DBRS believes EGD has sufficient liquidity to fund its current working capital needs. However, any combination of cold weather and high gas prices in the future could exhaust the Company's available liquidity. Should that event occur, ENB is expected to continue to provide liquidity support in a timely manner for the Company, as evidenced in winter 2014.

Debt Maturities Table

As at June 30, 2016 (CA$ million)	2016	2017	2018	2019	2020	Thereafter	Total
Medium-term notes and debenture	2	502	2	2	400	2,772	3,680

- EDG has approximately $502 million of medium-term notes due in 2017. The refinancing risk is manageable given EGD's strong credit quality.
- In addition to the above table, in August 2016, EDG issued $300 million medium-term notes (unsecured), maturing August 2026. The purpose of the debt issuance was to pay down short-term debt and for financing capital expenditures. DBRS conducted a pro forma review on the new debt issuance and is of a view that the Company's capital structure remains within the current rating range.
- EGD is subject to an EBIT-interest covenant of two times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
  - The covenant does not apply to debt issuances for debt refinancing.
  - The Company was in compliance with the covenant at the end of June 2016.

Inter-Company Subordinated Loans

- As of June 30, 2016, EGD owned $825 million of Class D, non-voting, redeemable, retractable preferred shares of IPL, which is 100% owned by ENB.
- The Company owes IPL $375 million in loans ($200 million due in 2049 and $175 million due in 2051), which are deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years, and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company. The default of the subordinated loans cannot trigger a default of senior debt.
- Investment income in the form of dividends from IPL was approximately $63 million in 2015 ($31 million for H1 2016), whereas the interest expense on the subordinated loans from IPL was approximately $27 million ($13 million for H1 2016).
- DBRS excludes the subordinated loans and its investment in IPL from its calculation of the Company's capital structure.

Regulation

2016 Rate Application

In January 2016, the OEB issued a decision on its multi-year demand side management (DSM). This decision allowed for an increase of 2016 costs, resulting in a revenue deficiency when compared with the 2016 interim order (issued in December 2015). In May 2016, the OEB approved the final rate order (the 2016 Final Order), effective as of January 1, 2016. The new rate was implemented on July 1, 2016. The 2016 Final Order allowed the Company to collect $14 million for the recovery of the revenue deficiency related to the January 2016 through June 2016 time period.

Gas Distribution: Ontario

In 2013, the Company's rates were based on the 2013 settlement relating to the cost-of-service (COS) rate application. In July 2014, the OEB rendered a decision on the Company's 2014–2018 customized IR application, with a subsequent decision and rate order provided in August 2014. The decision also approved final 2014 allowed revenues and rates with an ROE of 9.36% based on a 36% deemed common equity component of rate base. The revenue requirement is updated annually based on volumes, DSM, and pension and postretirement benefits (which are passed through to ratepayers). In May 2015, the OEB approved final rates for 2015. In December 2015, OEB approved interim rates for 2016.

The key features of the customized IR plan include the following:
1. Annual allowed revenue updates for selected items that help reduce forecast risk:

- Volumes are to reflect updated customer conditions, contract market volumes and average use.
- The customer care, DSM, pension and other post-employment benefits are to be updated annually and be treated as pass-through amounts from other approved mechanisms.
- The cost of capital is to be updated annually (approved ROE 9.19% in 2016) using the OEB approved parameters.

2. Earning sharing: To the extent the Company's actual return on the approved equity level represented by normalized earnings (excluding the effects of weather) exceeds the approved ROE for that year, the over-earnings will be shared equally between the Company and customers. However, customers will not share earning deficits that are below the approved ROE.

3. Adjustments: Several approved deferral and variance accounts are in place for the recovery of costs that deviate from those assumed in developing the customized IR plan. The customized IR plan also includes a z-factor mechanism for the Company to recover expenses above a defined threshold ($1.5 million within a year), to the extent any such expenses result from new regulatory orders and/or changes in statutory obligations.

4. Off ramps: An OEB review will be triggered if the Company's ROE on a normalized basis varies more than 300 basis points (either negative or positive) relative to the approved ROE for that year. The regulatory review will determine the reasons for variance in earnings and could either result in adjustments to the customized IR plan or a return to COS regulation.

Gas Storage: Ontario

- EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers (since November 2006) within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates.

Transportation: National Energy Board (NEB)

- TransCanada Pipelines Limited (TransCanada) transported approximately 73% of the annual natural gas requirements of EGD's customers in 2015. The remainder was transported through contracts with Alliance Pipeline Canada, Alliance Pipeline U.S., Vector Pipeline and others.
- The Company has Firm Transportation (FT) contracts with TransCanada for a portion of the requirement. Effective July 2013, the NEB approved new tolls on the FT service for TransCanada. Under the new tolls, the Company is required to pay TransCanada the demand component regardless of the volume transported.
- Transportation costs are passed through to customers.

Gas Distribution: New York

- The Company owns St. Lawrence Gas Company, Inc. (SLG), which provides natural gas distribution services to 16,000 customers in New York State. SLG is regulated by the New York State Public Service Commission under COS and is viewed as relatively stable.
- The approved ROE for 2015 was 10.5% (2014: 10.5%) on deemed equity of 50% (2014: 50%). Any earnings above 11% will be shared equally with ratepayers.
- SLG has no exposure to natural gas price risk, with gas supply costs being adjusted annually subject to regulatory review.
- SLG started construction on the Franklin Project in August 2012 following regulatory approval in July 2012. The total capital cost through 2018 is estimated to be USD 52 million. SLG had spent approximately USD 51 million by the end of 2015. The Franklin Project is expected to add 4,400 potential customers to the system.

Regulation (CONTINUED)

Agreement with TransCanada Pipelines Limited (TransCanada)

- In September 2013, EGD, Union Gas Limited and Gaz Métro Limited Partnership reached an agreement with TransCanada. The agreement was intended to modify the tolling structure of TransCanada's Mainline system.
- In December 2014, the NEB substantially approved the term of the agreement through its approval of TransCanada's 2015–2020 Mainline toll application.
- Under the new toll structure, the Company has to pay TransCanada a fixed charge regardless of the volume consumed. Under the old toll structure, EGD paid a fixed charge and a variable charge, depending on the volume.
- All transportation costs are passed through to customers.

Enbridge Gas Distribution Inc.

Balance Sheet (US GAAP)

(CA$ millions)	Jun. 30 2016	Dec. 31 2015	Dec. 31 2014		Jun. 30 2016	Dec. 31 2015	Dec. 31 2014
Assets				**Liabilities & Equity**			
Cash & equivalents	129	36	17	S.T. borrowings	571	666	1,151
Accounts receivable	475	314	339	Current portion of LT debt	300	2	2
Inventories	281	547	563	Accounts payable	171	201	184
Regulatory assets	0	216	567	Operating accrued liabilities	220	396	351
Prepaid expenses & others	7	270	283	Regulatory liabilities	102	136	233
				Others	213	224	188
Total Current Assets	**892**	**1,383**	**1,769**	**Total Current Liabilities**	**1,577**	**1,625**	**2,109**
Net fixed assets	7,258	7,081	6,268	Long-term (LT) debt	3,371	3,681	3,125
Future income tax assets	0	8	8	Deferred income taxes	538	524	463
Goodwill & intangibles	158	157	161	Inter-company subordinated loans	375	375	375
Investments in affiliates	825	825	825	Other LT liabilities	839	847	943
Regulatory assets	550	526	711	Preferred shares	100	100	100
Deferred and others	0	22	19	Shareholders equity	2,883	2,850	2,646
Total Assets	**9,683**	**10,002**	**9,761**	**Total Liab. & SE**	**9,683**	**10,002**	**9,761**

Balance Sheet & Liquidity & Capital Ratios

	6 mos. Jun. 30 2016	6 mos. Jun. 30 2015	12 mos. Jun. 30 2016	Year ended December 31 2015	2014	2013
Current ratio (times)	0.57	0.76	0.57	0.85	0.84	0.72
Cash flow/Capex (times)	1.06	0.91	0.57	0.56	0.86	0.95
(Cash flow - Dividends)/Capex (times)	0.69	0.63	0.34	0.34	0.54	0.58
Dividend payout ratio	71.3%	62.8%	99.1%	90.9%	83.3%	93.1%
Dividends/Cash flow	34.9%	30.9%	41.2%	38.7%	37.3%	38.5%
Profitability Ratios						
EBITDA margin	61.2%	62.8%	56.3%	57.2%	57.3%	57.5%
EBIT margin	37.8%	40.5%	30.7%	32.3%	32.5%	31.4%
Profit margin	24.6%	27.1%	19.4%	20.8%	21.3%	18.6%
Return on equity	11.5%	13.2%	7.8%	8.5%	9.2%	8.7%
Return on capital	6.0%	7.3%	4.4%	4.4%	5.0%	5.6%
Allowed ROE (EGD)	9.19%	9.30%	9.19%	9.30%	9.36%	8.93%
Allowed ROE (St. Lawrence)	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%
Key Credit Metrics						
Cash flow/Total debt 1	15.7%	18.8%	12.7%	13.1%	12.8%	16.4%
Total debt/Capital 1	58.7%	57.9%	58.7%	59.5%	60.9%	55.5%
EBITDA gross interest coverage (times)	4.34	4.99	3.72	4.01	4.18	4.72
EBIT gross interest coverage (times)	2.67	3.20	2.02	2.26	2.37	2.58
Adjusted EBIT interest coverage (times) 2	2.89	3.49	2.26	2.52	2.61	2.85
Fixed-charge coverage	2.64	3.16	1.99	2.22	2.33	2.52

1 Excludes inter-company subordinated loans. 2 Includes intercompany preferred dividends from IPL (less of interest expense on subordinated loans from IPL).

Rating History

	Current	2015	2014	2013	2012
Issuer Rating	A	A	A	A	A
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

Previous Report

- Enbridge Gas Distribution Inc., Rating Report: March 28, 2016.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Rating Report

Enbridge Gas Distribution Inc.

DBRS

Insight beyond the rating.

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating Update

On September 13, 2017, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debentures & Medium-Term Notes rating of Enbridge Gas Distribution Inc. (EGD or the Company) at "A," as well as its Commercial Paper rating at R-1 (low) and its Cum. & Cum. Redeemable Convertible Preferred Shares rating at Pfd-2 (low). All trends are Stable. The rating confirmations reflect EGD's stable business risk profile and good financial metrics as at June 30, 2017, albeit modestly weaker than in 2016.

EGD's business risk profile remained strong, supported by a large customer base and the stable regulatory framework in the Province of Ontario. EGD is in the fourth year of a five-year customized Incentive Regulation (IR) plan through 2018. In December 2016, EGD received the final rate order on its 2017 rate application from the Ontario Energy Board (OEB). The rate order lowered EGD's return on equity (ROE) for 2017 to 8.78% from 9.19% in 2016, while the deemed equity at 36.00% in the capital structure remains unchanged. DBRS does not view the decrease in ROE to have a material impact on EGD's earnings and cash flow, as EGD continues to benefit from a growing rate base.

The completion of the Western and Eastern segments of the Greater Toronto Area (GTA) expansion project (the GTA Project) in 2016 significantly reduced the construction risk associated with the project. The cost of the GTA Project is estimated to be approximately $875 million. Estimated cost overruns of approximately $185 million are not expected to be added to the rate base until the Company's rebasing year in 2019.

EGD's credit metrics have been under pressure during the construction of the GTA Project but remained solid in H1 2017. Although EGD's capital structure has been stable over the past few years, the cash flow-to-debt ratio and EBIT-to-interest coverage ratio in H1 2017 were negatively affected by lower earnings caused mainly by warmer weather and the timing of the cost recovery. However, these two ratios are expected to improve over the medium term, reflecting incremental cash flow from a higher rate base and a reduction in capital expenditures (capex). DBRS is of the view that given the current regulatory regime in Ontario, the rating upside is limited. However, a negative rating action is possible if any of the following occurs: (1) an adverse decision by the OEB or a change in EGD's business structure that negatively affects EGD's business risk profile or (2) the cash flow-to-debt ratio declines further, moving to below the "A" range, and is unlikely to recover within a reasonable time frame.

Financial Information

	6 mos. to June 30		12 mos. to June 30	Year ended December 31		
	2017	**2016**	**2017**	**2016**	**2015**	**2014**
Cash flow/total debt 1	14.2%	15.7%	12.3%	12.7%	13.1%	12.8%
Total debt in capital structure 1	58.0%	58.7%	58.0%	57.8%	59.5%	60.9%
EBIT interest coverage (times)	2.54	2.71	1.97	2.05	2.26	2.37

1 Debt excludes inter-company subordinated loans of $375 million.

Issuer Description

EGD is a regulated natural gas distributor, serving approximately 2.15 million customers in Ontario as at September 1, 2017. Other operations include regulated transportation services and regulated and unregulated storage services.

Rating Considerations Details

Strengths

1. Low-risk regulated operations
The regulatory regime in Ontario provides the Company with the following benefits: (a) gas supply costs are passed through to customers, with quarterly adjustments to rates, subject to regulatory review, and (b) a customized IR plan (2014–2018) that provides EGD with the opportunity to earn the allowed ROE through operational efficiency, with the excess above the allowed ROE for each year to be shared equally with ratepayers. Forecast risk during this customized IR period is partially mitigated through annual updates on volumes (by EGD), demand-side management (DSM) and pension and post-retirement benefits (which are passed through to ratepayers).

2. Strong franchise area with a large customer base
EGD is the largest regulated natural gas distributor in Canada, serving approximately 2.15 million active customers in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong compared with other service areas in Canada. EGD's large customer base provides it with the size and scale to operate efficiently during its customized IR period.

3. Good financial profile
EGD maintains a good financial profile with a reasonable balance sheet and solid credit metrics. EGD is committed to maintaining its capital structure within the regulatory capital structure of 64% debt and 36% equity. Although the Company's cash flow-to-debt has been under pressure during the construction of the GTA Project in the past two years, it is expected to improve over the medium term as the rate base grows following the completion of the GTA Project in 2016.

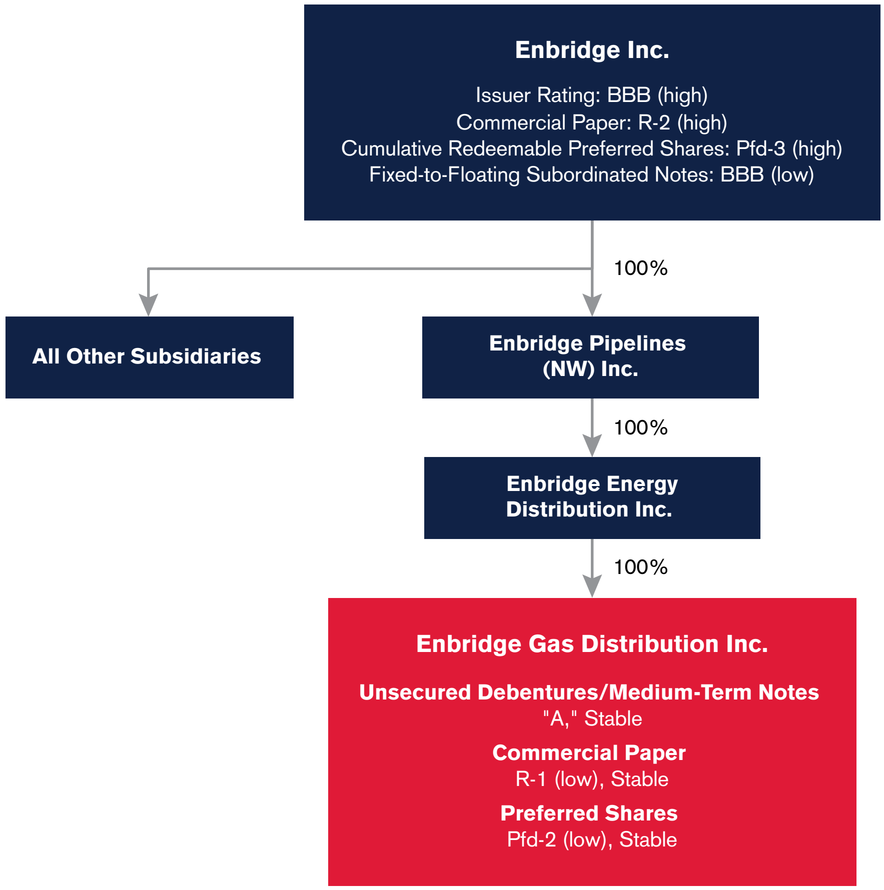
Challenges

1. Weather-related volume risk
Weather risk remains significant, as forecast volumes (based on normalized weather) are built into the Company's base rates, while actual usage varies with the weather. Therefore, colder-than-normal weather in any given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. However, normalized weather is updated annually throughout the customized IR period by incorporating the most recent weather trend, thereby mitigating any significant sustained exposure to weather conditions.

2. Managing operating costs under the IR plan
EGD is in the fourth year of its five-year customized IR plan. Managing operating costs is critical for the Company to achieve or exceed the allowed ROE. Earnings below the allowed ROE will not be recovered from customers unless actual ROE is 300 basis points below the allowed ROE, at which point the Company can request a regulatory review.

3. Potential regulatory lag
EGD faces potential regulatory lag with respect to the recovery of natural gas costs. Although the Company is allowed to pass on to customers all natural gas costs with quarterly adjustments, potential regulatory lag still exists. In the event that natural gas costs increase substantially within a short period of time, the Company may have to recover such costs over a longer time frame than it normally does. In addition, the cost overruns associated with the GTA Project (estimated to be approximately $185 million) are not expected to be added to the rate base until the Company's rebasing in 2019.

Simplified Organizational Chart



The GTA Project

- The GTA Project consists of two new segments of pipelines (Western and Eastern) and related facilities to upgrade the existing system that delivers natural gas to several municipalities within the GTA. During 2016, both the Western and Eastern segments were placed into service while related facilities will be upgraded throughout 2017.
- The schedule and cost of the GTA Project is estimated to be approximately $875 million. Total spending on the GTA Project was approximately $865 million as at the end June 2017.
- The Company funded this project with a mixture of cash flow from operations, equity injections from the parent and new debt issuances. The funding is subject to maintaining the debt leverage within the regulatory capital structure.
- In October 2016, EGD and TransCanada Pipelines Limited (TransCanada; rated A (low) with a Stable trend by DBRS) entered into an agreement in which TransCanada will provide firm transportation (FT) services from the Parkway Pipeline to TransCanada's Mainline Pipeline at Albion King's North. The Albion Pipeline was placed into service as part of the GTA Project. The transportation agreement has a 15-year term. The transportation costs are passed through to customers.

Recent Development

- On August 31, 2017, EGD announced the sale of its St. Lawrence Gas business (which serves approximately 16,003 customers) for approximately USD 70 million. The proposed sale will not have any impact on EGD's credit profile as it accounted for less than 1% of EGD's 2016 cash flow.

Earnings and Outlook

	6 mos. to June 30		12 mos. to June 30	Year ended December 31		
($ millions)	2017	2016	2017	2016	2015	2014
Gas distribution revenue	1,571	1,482	2,526	2,437	3,043	2,803
Gas transportation service revenue	235	187	378	330	344	305
Gas commodity and distribution costs	-1,201	-1,047	-1,790	-1,636	-2,322	-2,046
Gas distribution margin	605	622	1,114	1,131	1,065	1,062
Other revenue	55	45	110	100	97	92
Net revenue, excluding natural gas costs	660	667	1,224	1,231	1,162	1,154
EBITDA	411	408	700	697	665	661
EBIT	241	252	364	375	375	375
Earnings sharing	-18	-8	-13	-3	-7	-12
Other income 1	32	33	72	73	66	66
Interest expense (external)	-95	-93	-185	-183	-166	-158
Interest expense (inter-company)	-14	-14	-27	-27	-27	-29
Net income before extra. items	148	164	214	230	242	246
Extra items	0	0	0	0	-8	0
Reported Net Income	**148**	**164**	**214**	**230**	**234**	**246**

1 Includes inter-company preferred dividend income.

Summary

- **H1 2017:** EBIT was slightly lower than H1 2016, reflecting the following factors: (1) warmer weather in H1 2017 and (2) higher depreciation expense because of a larger rate base, partially offset by higher transportation revenues, higher distribution charges from growth in the rate base, a higher customer count and lower operating costs.
- Gas transportation service revenue represents services charged to customers who do not purchase natural gas from EGD. Higher transportation revenue in H1 2017 reflected new tariffs, which began in late 2016.
- Other revenue mostly represents revenues from storage operations, which include regulated and unregulated storage activities. Higher other revenues in H1 2017 largely reflected higher revenues from unregulated operations.
- Earnings sharing in the above table reflects the estimated amount of earnings above the allowed regulated earnings that would have to be shared with ratepayers.
- Other income includes dividends of approximately $32 million in H1 2017 ($63 million in 2016) from EGD's $825 million investment in its affiliate, IPL System Inc. (IPL), the holder of the Company's $375 million inter-company subordinated loans. Interest expense on the loans is approximately $27 million per year.

Outlook

- Assuming normal weather conditions in Q4 2017, the earnings outlook for 2017 is neutral to slightly negative, reflecting warmer weather in Q1 2017. The weather impact is expected to be partly offset by higher earnings because of continued growth in the rate base, especially related to the GTA Project. Earnings sharing is expected to continue to be positive for EGD as a result of its operational efficiency.

Financial Profile

	6 mos. to June 30		12 mos. to June 30	Year ended December 31		
($ millions, where applicable)	2017	2016	2017	2016	2015	2014
Cash Flow from Operations	**318**	**332**	**550**	**564**	**569**	**549**
Preferred share dividends	-1	-1	-2	-2	-2	-2
Common share dividends	-122	-116	-239	-233	-218	-203
Capex	-446	-313	-735	-602	-1,023	-637
Free Cash Flow before WC	**-251**	**-98**	**-426**	**-273**	**-674**	**-293**
Changes in working capital (WC)	262	382	-42	78	325	-1,031
Non-recurring & adjustments	0	0	0	0	-52	52
Net Free Cash Flow	**11**	**284**	**-468**	**-195**	**-401**	**-1,272**
Dispositions & acquisitions (net)	0	0	0	0	8	0
Other investing activities	-32	-100	-70	-138	151	17
Cash Flow before Financing	**-21**	**184**	**-538**	**-333**	**-242**	**-1,255**
Net changes in equity	0	0	280	280	200	150
Net changes in external debt	50	-86	235	99	234	902
Net changes in affiliated debt	-1	-5	-2	-6	-170	189
Other financing	0	0	0	0	-3	-2
Change in Cash	**28**	**93**	**-25**	**40**	**19**	**-16**
Total debt 1	4,475	4,242	4,475	4,427	4,336	4,278
Total debt/capital 1	58.0%	58.7%	58.0%	57.8%	59.5%	60.9%
EBIT interest coverage (times)	2.54	2.71	1.97	2.05	2.26	2.37
Cash flow/total debt 1	14.2%	15.7%	12.3%	12.7%	13.1%	12.8%
Dividends/cash flow	38.4%	34.9%	43.5%	41.3%	38.3%	37.0%

1 Debt excludes inter-company subordinated loans of $375 million.

Summary

- Except for the capital structure, EGD's other metrics have been under pressure during the GTA Project construction period but have remained solid and supportive of the current ratings.
  - The cash flow-to-debt ratio and EBIT-to-interest coverage in H1 2017 weakened slightly as a result of lower cash flow, which largely reflected the timing of cash flow from the GTA Project and lower earnings because of warmer weather during the period.
  - The debt-to-capital ratio as at June 30, 2017, was stronger than the regulated capital structure of 64% debt and 36% deemed equity. This reflected the fact that the equity base is supported by EGD's investments in IPL, as discussed on the previous page.
- High capex in 2015 and 2016 largely reflected capital spending on the GTA Project and system improvements and upgrades. Capex during this period was financed with internally generated cash flows, equity injections from EGD's parent and new debt issuance. Financing was consistent with the Company's plan to maintain the capital structure within the regulatory capital structure.
- The dividend payout in terms of cash flow has remained relatively low at around the 40% range.

Outlook

- DBRS expects the Company's capital structure to remain stable and its cash flow-to-debt and interest coverage ratios to improve over the medium term, as cash flow is expected to increase in line with the growing rate base.

Liquidity and Long-Term Debt Maturities

Bank Lines/Liquidity

Credit Facilities				As at June 30, 2017
($ millions)	Total Facilities	Used	Available	Maturity
Enbridge Gas Distribution Inc.	1,000	675	325	Jul. 2019
Total	**1,000**	**675**	**325**	

- EGD requires relatively high liquidity to finance its volatile and seasonal working capital needs, which are heavily influenced by natural gas prices and gas storage for the heating season.
- EGD's current commercial paper program of $1.0 billion is fully backed by the $1.0 billion revolving term credit facility (unsecured), maturing in July 2019.
- EGD has sufficient liquidity to fund its current working capital needs. However, any combination of cold weather and high gas prices in the future could exhaust the Company's available liquidity. Should that event occur, Enbridge Inc. (Enbridge; rated BBB (high) with a Stable trend by DBRS) is expected to provide liquidity support in a timely manner for the Company, as evidenced in winter 2014. During the cold weather in 2014, as gas prices were extremely high, Enbridge set up a $300 million inter-company credit facility to support EGD. This inter-company facility was not renewed in 2016.

Debt Maturities Table

As at December 31, 2016	2017	2018	2019	2020	2021	Thereafter	Total
($ millions)							
Medium-term notes & debentures (EGD)	500	0	0	400	175	2,896	3,971

- Of the $500 million of medium-term notes due in 2017, $300 million was due in April and was refinanced through the credit facility while the remaining $200 million will mature in December 2017. EGD expects to refinance the maturities through funds from operations, the available credit facility and new debt issuances.
- EGD is subject to an EBIT-to-interest covenant of 2.0 times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
  - The covenant does not apply to debt issuances for debt refinancing.
  - The Company was in compliance with the covenant as at June 30, 2017.

Inter-Company Subordinated Loans

- As at June 30, 2017, EGD owned $825 million of Class D, non-voting, redeemable, retractable preferred shares of IPL, which is 100% owned by Enbridge.
- The Company owes IPL $375 million in loans ($200 million due in 2049 and $175 million due in 2051), which are deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years, and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company. A default of the subordinated loans cannot trigger a default of senior debt. The inter-company subordinated loans are excluded from the calculation of the debt-to-capital ratio.

Regulation

Rate Application

- In December 2016, the OEB approved the final rate order, effective January 1, 2017 (the 2017 Final Order). The 2017 Final Order is in accordance with the Company's approved customized IR plan.
  - Allowed ROE for 2017 is 8.78% compared with 9.19% for 2016.
  - The average rate base for 2017 is $6,024 million compared with $5,808 million for 2016.
- The Company filed its 2018 rate application in August 2017. A regulatory decision is expected in late 2017.
- EGD is currently in the fourth year of a five-year customized IR plan (2014–2018). The key features of the Company's customized IR plan include the following:

1. Annual allowed revenue updates for selected items that help reduce forecast risk:

- Volumes are to reflect updated customer conditions, contract market volumes and average use.
- The customer care, DSM, pension and other post-employment benefits are to be updated annually and be treated as pass-through amounts from other approved mechanisms.
- The cost of capital is to be updated annually, using the OEB-approved parameters.

2. Earnings sharing: To the extent the Company's actual return on the approved equity level represented by normalized earnings (excluding the effects of weather) exceeds the approved ROE for that year, the over-earnings will be shared equally between the Company and customers. However, customers will not share earning deficits that are below the approved ROE.

3. Adjustments: Several approved deferral and variance accounts are in place for the recovery of costs that deviate from those assumed in developing the customized IR plan. The customized IR plan also includes a Z-factor mechanism for the Company to recover expenses above a defined threshold ($1.5 million within a year), to the extent any such expenses result from new regulatory orders and/or changes in statutory obligations.

4. Off-ramps: An OEB review will be triggered if the Company's ROE on a normalized basis varies more than 300 basis points (either negative or positive) relative to the approved ROE for that year. The regulatory review will determine the reasons for variance in earnings and could either result in adjustments to the customized IR plan or a return to cost-of-service regulation.

Gas Storage: Ontario

- EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers (since November 2006) within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates.

Transportation: National Energy Board (NEB)

- TransCanada transported approximately 83%, or 9.9 billion cubic metres, of EGD's natural gas requirements in 2016. The remainder was transported through contracts with Alliance Pipeline Canada, Alliance Pipeline U.S., Vector Pipeline and others.
- The Company has FT contracts with TransCanada for a portion of the requirement. Effective July 2013, the NEB approved new tolls on the FT service for TransCanada. Under the new tolls, the Company is required to pay TransCanada the demand component regardless of the volume transported.
- Transportation costs are passed through to customers.
- In December 2014, the NEB substantially approved the term of the agreement between TransCanada, EGD, Union Gas Limited (rated "A" with a Stable trend by DBRS) and Gaz Métro Limited Partnership, which was entered into in March 2014. The agreement modified the tolling structure of TransCanada's Mainline system. Under the new toll structure, the Company has to pay TransCanada a fixed charge regardless of the volume consumed. Under the old toll structure, EGD paid a fixed charge and a variable charge, depending on the volume. All transportation costs are passed through to customers.

Enbridge Gas Distribution Inc.

Balance Sheet (U.S. GAAP)

($ millions)	June 30 2017	December 31 2016	December 31 2015
Assets			
Cash & equivalents	104	76	36
Accounts receivable	537	329	314
Inventories	316	512	547
Regulatory assets		66	216
Prepaid expenses & others	64	334	270
Total Current Assets	**1,021**	**1,317**	**1,383**
Net fixed assets	7,485	7,418	7,081
Future income tax assets	0	0	8
Goodwill & intangibles	400	158	157
Investments in affiliates	825	825	825
Regulatory assets	620	568	526
Deferred and others	0	8	9
Total Assets	**10,351**	**10,294**	**9,989**

	June 30 2017	December 31 2016	December 31 2015
Liabilities & Equity			
S.T. borrowings	805	457	666
Current portion of L.T. debt	200	500	2
Accounts payable & accrued	524	711	734
Regulatory liabilities		96	136
Others	99	95	87
Total Current Liabilities	**1,628**	**1,859**	**1,625**
L.T. debt	3,470	3,470	3,668
Deferred income taxes	570	532	524
Inter-company subordinated loans	375	375	375
Other L.T. liabilities	1,074	846	847
Preferred shares	100	100	100
Shareholders' equity	3,134	3,112	2,850
Total Liab. & SE	**10,351**	**10,294**	**9,989**

	6 mos. to June 30 2017	6 mos. to June 30 2016	12 mos. to June 30 2017	Year ended December 31 2016	Year ended December 31 2015	Year ended December 31 2014
Payout Ratios						
Cash flow/capex (times)	0.71	1.06	0.75	0.94	0.56	0.86
Dividend payout ratio	83.1%	71.3%	112.6%	102.2%	90.9%	83.3%
Dividends/cash flow	38.4%	34.9%	43.5%	41.3%	38.3%	37.0%
Key Credit Metrics						
Cash flow/total debt [1]	14.2%	15.7%	12.3%	12.7%	13.1%	12.8%
Total debt/capital [1]	58.0%	58.7%	58.0%	57.8%	59.5%	60.9%
EBITDA gross interest coverage (times)	4.33	4.39	3.78	3.81	4.01	4.18
EBIT gross interest coverage (times)	2.54	2.71	1.97	2.05	2.26	2.37
Fixed-charges coverage (times)	2.51	2.68	1.95	2.03	2.24	2.35
Debt/EBITDA (times)	5.44	5.20	6.39	6.35	6.52	6.47
Profitability Ratios						
EBITDA margin	62.3%	61.2%	57.2%	56.6%	57.2%	57.3%
EBIT margin	36.5%	37.8%	29.7%	30.5%	32.3%	32.5%
Profit margin	22.4%	24.6%	17.5%	18.7%	20.8%	21.3%
Return on equity	9.2%	11.1%	6.9%	7.5%	8.5%	9.2%
Allowed ROE (EGD)	8.78%	9.19%		9.19%	9.30%	9.36%
Mid-year rate base (EGD)	6,024			5,808		

1 Debt excludes inter-company subordinated loans of $375 million.

Rating History

	Current	2016	2015	2014	2013
Issuer Rating	A	A	A	A	A
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

Previous Report

- Enbridge Gas Distribution Inc.: Rating Report, September 22, 2016.

Commercial Paper Limit

- $1.0 billion.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

The DBRS group of companies consists of DBRS, Inc. (Delaware, U.S.)(NRSRO, DRO affiliate); DBRS Limited (Ontario, Canada)(DRO, NRSRO affiliate); DBRS Ratings Limited (England and Wales) (CRA, NRSRO affiliate, DRO affiliate); and DBRS Ratings México, Institución Calificadora de Valores S.A. de C.V. (Mexico)(CRA, NRSRO affiliate, DRO affiliate). Please note that DBRS Ratings Limited was registered as an NRSRO affiliate on July 14, 2017. For more information on regulatory registrations, recognitions and approvals, please see: http://www.dbrs.com/research/225752/highlights.pdf.

Rating Report

Enbridge Gas Distribution Inc.

DBRS

Insight beyond the rating.

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating Update

On September 7, 2018, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debentures & Medium-Term Notes rating of Enbridge Gas Distribution Inc. (EGD or the Company) at "A," as well as its Commercial Paper rating at R-1 (low) and its Cum. & Cum. Redeemable Convertible Preferred Shares rating at Pfd-2 (low). All trends are Stable. The rating confirmations reflect EGD's stable business risk profile through 2018 and its improved credit metrics as at June 30, 2018. The Stable trends reflect DBRS's expectation that the amalgamation of EGD and Union Gas Limited (Union Gas, rated "A," Stable trend by DBRS) (the Combined Entity), approved by the Ontario Energy Board (OEB) on August 30, 2018, and potentially taking effect in 2019, subject to Enbridge Inc.'s approval (Enbridge, rated BBB (high), Stable trend by DBRS), would not have a material impact on the Combined Entity's credit profile.

In December 2017, EGD received the final rate order from the OEB on its 2018 rate application (the OEB Decision), which increased EGD's return on equity (ROE) for 2018 to 9.00%, from 8.78% in 2017, and maintained the deemed equity in the capital structure at 36%. The increase in ROE will have a slight positive impact on EGD's earnings and cash flow in 2018. Following the amalgamation expected to be effective January 1, 2019, under the Combined Entity, the size of the franchise area and the number of customers will significantly increase. The key determinations in the OEB Decision are expected to provide a stable framework for the Combined Entity's operations to support the current ratings.

EGD's credit metrics have been under pressure during last few years because of large capex. However, higher earnings and cash flow, as well as lower debt levels, resulted in improved credit metrics in H1 2018. These metrics are not expected to materially change under the Combined Entity. DBRS expects the capital structure and the dividend policy for the Combined Entity to remain supportive of the current ratings because of the strong regulatory protection of a regulated utility in Ontario.

Based on DBRS's review of the OEB Decision, DBRS does not expect the ratings of the Combined Entity to change from EGD's ratings because the amalgamation would be a merger of two "A"-rated regulated entities operating in the same regulatory jurisdiction. However, a negative rating action could be taken if (1) there is an adverse regulatory change that has a negative impact on the Combined Entity's business profile or (2) the Company experiences a significant deterioration of its credit metrics on a sustained basis. These scenarios are considered unlikely by DBRS.

Financial Information

	6M June 30		12M June 30	Year ended December 31		
Key Credit Metrics	**2018**	**2017**	**2018**	**2017**	**2016**	**2015**
Cash flow-to-debt	15.4%	13.0%	12.1%	10.3%	11.6%	10.7%
Debt-to-capital 1	60.2%	60.3%	60.2%	60.9%	60.3%	62.3%
EBIT gross interest coverage (times) 2	3.95	2.79	2.90	2.34	2.36	2.49

1 Includes operating leases treated as debt. 2 Excludes interest on affiliate loans.

Issuer Description

EGD is a regulated natural gas distributor, serving approximately 2.19 million customers in Ontario as at June 30, 2018. Other operations include regulated transportation services and regulated and unregulated storage services.

Rating Considerations

Strengths

1. Low-risk regulated operations

Substantially all of EGD's assets are regulated by the OEB, which provides the Company with the following benefits: (a) relatively predictable earnings and cash flow and a reasonable mechanism for capex recovery under the current custom incentive regulation (IR) plan (2014–2018); (b) full recovery of gas supply costs with quarterly adjustments, subject to regulatory review; and (c) reduced forecast risk during the current IR period through annual update on volumes by EGD. The current IR period will end at the end of 2018. Following the OEB approval of the proposed amalgamation of EGD and Union Gas on August 30, 2018, and assuming Enbridge's approval, DBRS expects the regulatory regime to continue to remain stable going forward under the new rate-setting mechanism by the OEB (see Regulation section for more details).

2. Strong franchise area with a large customer base

EGD is currently the largest regulated natural gas distributor in Canada, serving approximately 2.19 million active customers in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong compared with other service areas in Canada. EGD's large customer base provides it with the size and scale to operate efficiently during its custom IR period. Union Gas currently serves approximately 1.5 million customers in over 400 communities across northern, southern and eastern Ontario. If the amalgamation is successfully completed, the Combined Entity will have a much larger customer base of approximately 3.7 million.

3. Good financial profile

EGD maintains a good financial profile with a reasonable balance sheet and solid credit metrics. EGD is committed to maintaining its capital structure within the regulatory capital structure of 64% debt and 36% equity. Credit metrics improved in H1 2018, largely supported by a larger rate base and colder weather.

Challenges

1. Weather-related volume risk

Weather risk remains significant, as forecast volumes (based on normalized weather) are built into the Company's base rates, while actual usage varies with the weather. Therefore, colder-than-normal weather in any given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. However, normalized weather is updated annually throughout the custom IR period by incorporating the most recent weather trend, thereby mitigating any significant sustained exposure to weather conditions.

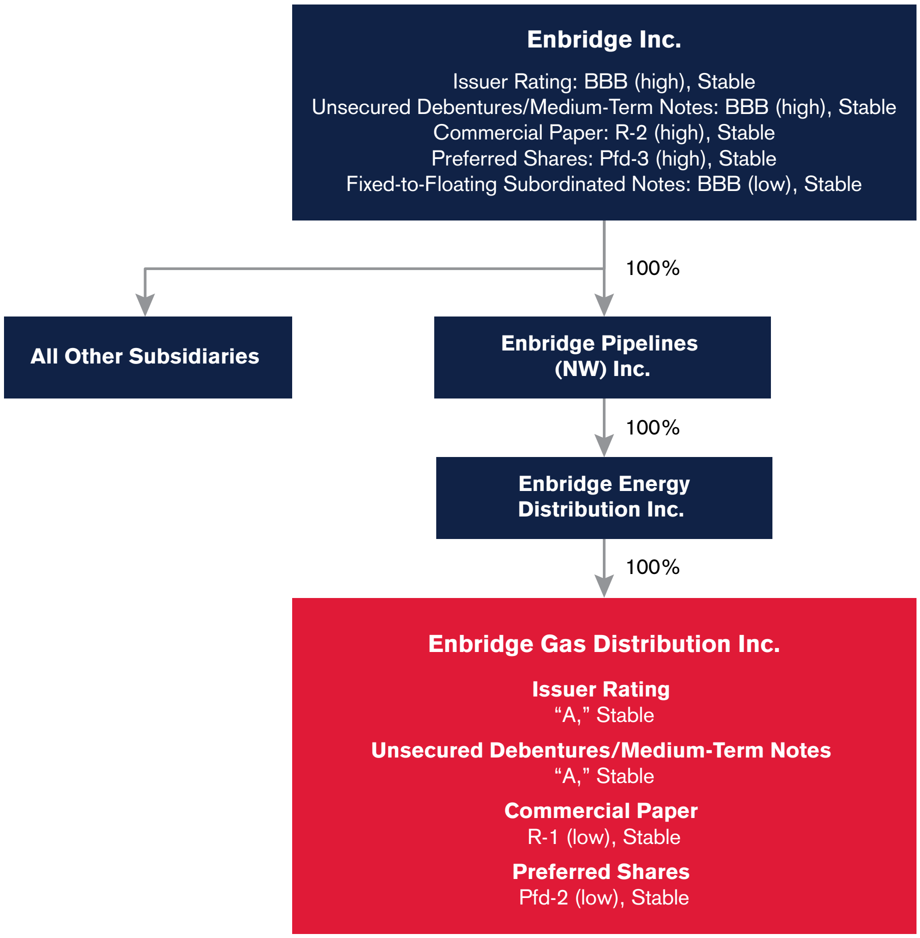
2. Managing operating costs under the IR plan

EGD is in the last year of its five-year custom IR plan. Managing operating costs is critical for the Company to achieve or exceed the allowed ROE. Earnings below the allowed ROE will not be recovered from customers unless actual ROE is 300 basis points below the allowed ROE, at which point the Company can request a regulatory review. DBRS expects the Combined Entity to continue to effectively manage its operating costs under the new rate-setting mechanism approved by the OEB (see Regulation section for more details).

3. Potential regulatory lag

EGD faces potential regulatory lag with respect to the recovery of natural gas costs. Although the Company can pass on to customers natural gas costs with quarterly adjustments, potential regulatory lag still exists. If natural gas costs increase substantially within a short period of time, the Company may have to recover such costs over a longer time frame than it normally does.

Simplified Organizational Chart



As of September 7, 2018.

- **The GTA Project:** The Greater Toronto Area (GTA) Project consists of two new segments of pipelines (Western and Eastern) and related facilities to upgrade the existing system that delivers natural gas to several municipalities within the GTA. During 2016, both the Western and Eastern segments were placed into service while related facilities were upgraded throughout 2017.
- **Transportation Contracts:** In March 2017, EGD and TransCanada Pipelines Limited (TransCanada; rated A (low) with a Stable trend by DBRS) entered into a 15-year agreement in which TransCanada will provide incremental pipeline transportation capacity (75,000 gigajoules/day) from the Parkway (GTA) in the EGD's franchise area. In October 2016, EGD and TransCanada entered into an agreement in which TransCanada will provide firm transportation services from the Parkway Pipeline to TransCanada's Mainline Pipeline at Albion King's North. The transportation agreement has a 15-year term. The transportation costs are passed through to customers.

Recent Development

- On August 30, 2018, the OEB approved the amalgamation application of EGD and Union Gas. The amalgamation still needs approval from Enbridge.
- On July 3, 2018, the Government of Ontario revoked the cap and trade program, but DBRS does not expect any material impact on the Company because costs related to compliance liabilities were passed through to customers via interim cap and trade unit rates.
- In August 2017, EGD announced the sale of its St. Lawrence Gas business (which serves approximately 16,003 customers) for approximately USD 70 million. The sale is expected to close in the first half of 2019.

Earnings and Outlook

	6M June 30		12M June 30	Year ended December 31		
(CAD millions)	**2018**	**2017**	**2018**	**2017**	**2016**	**2015**
Gas commodity and distribution revenue	1,190	1,082	2,868	2,760	2,437	3,043
Transportation of gas revenue	151	151	418	418	330	344
Other revenue	31	27	118	114	100	97
Total revenue	**1,999**	**1,861**	**3,430**	**3,292**	**2,867**	**3,484**
Gas Commodity & Distribution Costs	1,264	1,201	2,095	2,032	1,636	2,322
Operating & Administrative	242	254	508	520	514	497
Depreciation & Amortization	173	170	333	330	322	290
Earnings Sharing	0	18	6	24	3	7
Total Operating Costs	**1,679**	**1,643**	**2,942**	**2,906**	**2,475**	**3,116**
Operating Income	**320**	**218**	**488**	**386**	**392**	**368**
Gross Interest Expense	95	92	195	192	193	175
Capitalized Interest	0	0	(5)	(5)	(14)	(21)
Interest Expense	**108**	**105**	**217**	**214**	**206**	**181**
Operating Income Before Other Inc.	**212**	**113**	**271**	**172**	**186**	**187**
Other Income (Expense), net	38	37	65	64	73	70
Interest Income	0	0	0	0	0	0
Operating Profit Before Taxes	**250**	**150**	**336**	**236**	**259**	**257**
Income Taxes	42	2	26	(14)	14	14
Equity Earnings	0	0	0	0	0	0
Less: Noncontrolling Interests	0	0	0	0	0	0
Net Income bef. Extra. Items	**208**	**148**	**310**	**250**	**245**	**243**
Extraordinary Items	0	0	0	0	(15)	(9)
Net Income From Cont. Operations	**208**	**148**	**310**	**250**	**230**	**234**
Plus: Discontinued Operations	0	0	0	0	0	0
Reported Net Income	**208**	**148**	**310**	**250**	**230**	**234**

Summary

- A significant increase in earnings in H1 2018 compared with H1 2017 reflected colder weather, higher gas distribution charges and modestly lower operating and maintenance costs.
- Revenues include Gas Transportation Service revenue, which represents services charged to customers who do not purchase natural gas from EGD. Transportation revenue in H1 2018 was consistent with H1 2017.
- Other revenue mostly represents revenues from storage operations, which include regulated and unregulated storage activities.
- Other income includes dividends of approximately $38 million in H1 2018 ($63 million in 2017) from EGD's $825 million investment in its affiliate, IPL Systems, Inc. (IPL), the holder of the Company's $375 million inter-company subordinated loans. Interest expense on the loans is approximately $27 million per year.

Outlook

- Assuming normal weather conditions in Q4 2018, the earnings outlook for 2018 is positive, reflecting colder weather in Q1 2018 and continued growth in the rate base.

Financial Profile

	6M June 30		12M June 30	Year ended December 31		
(CAD millions)	2018	2017	2018	2017	2016	2015
Operating cash flow	**383**	**318**	**602**	**537**	**564**	**517**
Capex, equity investments, other	(444)	(478)	(766)	(800)	(740)	(872)
Dividends paid	(271)	(123)	(809)	(661)	(235)	(220)
Free cash flow (bef. work. cap. changes)	**(332)**	**(283)**	**(973)**	**(924)**	**(411)**	**(575)**
Changes in non-cash work. cap. items	489	260	256	27	78	325
Gross free cash flow	**157**	**(23)**	**(717)**	**(897)**	**(333)**	**(250)**
Business acquisitions, net of cash	0	0	0	0	0	0
Cash Extraordinary Items	0	0	0	0	0	0
Proceeds on sale of inv. & other activities (net)	0	0	0	0	0	8
Net free cash flow	**157**	**(23)**	**(717)**	**(897)**	**(333)**	**(242)**
Change in debt & equivalents	(176)	24	213	413	54	234
Change in note payable - affiliate	0	(1)	1	0	(6)	(170)
Change in equity & equivalents	0	0	500	500	280	200
Change in other liabilities	0	0	0	0	0	(3)
Change in cash & mktble. securities	19	0	3	(16)	5	(19)
Funding Sources	**(157)**	**23**	**717**	**897**	**333**	**242**
Total debt in capital structure 1	60.2%	60.3%	60.2%	60.9%	60.3%	62.3%
Cash flow/total debt	15.4%	13.0%	12.1%	10.3%	11.6%	10.7%
EBIT interest coverage (times)	3.39	2.38	2.50	2.01	2.03	2.10
EBIT interest coverage (times) 2	3.95	2.79	2.90	2.34	2.36	2.49
Fixed-charges coverage (times)	3.34	2.35	2.47	1.98	2.00	2.07
Dividends/Cash flow	70.8%	38.7%	134.4%	123.1%	41.7%	42.6%

1 Includes operating leases treated as debt. 2 Excludes interest on affiliate loans.

Summary

- EGD's credit ratios improved modestly in H1 2018, supported by higher cash flow and lower debt, resulting in stronger a cash flow-to-debt ratio for the 12 months ended June 30, 2018, compared with that of 2017.
- EBIT-to-interest coverage improved in H1 2018 because of higher operating income, as discussed in the Earning section.
- The debt-to-capital ratio as at June 30, 2018, remained relatively stable and was stronger than the regulated capital structure of 64% debt and 36% deemed equity. This reflected the fact that the equity base is supported by EGD's investments in IPL, as discussed on the previous page.

• Beginning 2017, EGD changed its dividend policy, paying dividends based on budgeted cash flow rather than budgeted earnings. As a result, significantly higher dividends were paid to the parent in 2017. The parent then injected equity back into EGD to maintain its capital structure and credit metrics at targeted levels.

Outlook

• DBRS expects the Company's credit metrics to remain stable in 2018. If the amalgamation is completed, DBRS also expects these ratios will not materially change for the Combined Entity because the Company will maintain its capital structure in line with the regulatory capital structure.

Liquidity and Long-Term Debt Maturities

Bank Lines/Liquidity

Credit Facilities

(CAD millions)	Total Facilities	Drawn [1]	Available	Maturity (As at June 30, 2018)
Enbridge Gas Distribution Inc.	1,017	794	223	July 2019
Total	**1,017**	**794**	**223**	

1 Includes commercial paper issuances, net of discount, that are backed by the $1.0 billion Revolving Term Credit Facility.

- EGD requires relatively high liquidity to finance its volatile and seasonal working capital needs, which are heavily influenced by natural gas prices and gas storage for the heating season.
- EGD's current commercial paper program of $1.0 billion is fully backed by the $1.0 billion revolving term credit facility (unsecured), maturing in July 2019.
- EGD has sufficient liquidity to fund its current working capital needs. However, any combination of cold weather and high gas prices in the future could exhaust the Company's available liquidity. Should that event occur, Enbridge is expected to provide liquidity support in a timely manner for the Company.

Debt Maturities Table

	As at December 31, 2017						
(CAD millions)	2018	2019	2020	2021	2022	Thereafter	Total
Medium-term notes and debenture	0	0	400	175	0	3,205	3,780

- Refinancing risk is low, as EGD has no medium-term notes and debentures due in 2018 and 2019.
- EGD is subject to an EBIT-to-interest covenant of 2.0 times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
  - The covenant does not apply to debt issuances for debt refinancing.
  - The Company was in compliance with the covenant as at June 30, 2018.

Inter-Company Subordinated Loans

- As at June 30, 2018, EGD owned $825 million of Class D, non-voting, redeemable, retractable preferred shares of IPL, which is 100% owned by Enbridge.
- The Company owes IPL $375 million in loans ($200 million due in 2049 and $175 million due in 2051), which are deeply subordinated to the debentures and medium-term notes. EGD can defer interest payments on the loans for up to five years, and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company. A default of the subordinated loans cannot trigger a default of senior debt.

Regulation

Rate application

- In December 2017, the OEB approved the final rate order, effective January 1, 2018 (the 2018 Final Order). The 2018 Final Order is in accordance with the Company's approved Custom IR plan.
  - Allowed ROE for 2018 is 9.00% (8.78% for 2017).
  - The average rate base for 2018 is $6,500 million ($5,900 million for 2017).
- The OEB also approved a quarterly rate adjustment application in March 21, 2018.

The five-year Custom IR plan (2014–2018)

The key features of the Company's Custom IR plan include the following:

1. Annual allowed revenue updates for selected items that help reduce forecast risk:

- Volumes are to reflect updated customer conditions, contract market volumes and average use.
- The customer care, demand-side management, pension and other post-employment benefits are to be updated annually and be treated as pass-through amounts from other approved mechanisms.
- The cost of capital is to be updated annually, using the OEB-approved parameters.

2. Earnings sharing: To the extent the Company's actual return on the approved equity level represented by normalized earnings (excluding the effects of weather) exceeds the approved ROE for that year, the over-earnings will be shared equally between the Company and customers. However, customers will not share earning deficits that are below the approved ROE.

3. Adjustments: Several approved deferral and variance accounts are in place for the recovery of costs that deviate from those assumed in developing the Custom IR plan. The Custom IR plan also includes a Z-factor mechanism for the Company to recover expenses above a defined threshold ($1.5 million within a year), to the extent any such expenses result from new regulatory orders and/or changes in statutory obligations.

4. Off-ramps: An OEB review will be triggered if the Company's ROE on a normalized basis varies more than 300 basis points (either negative or positive) relative to the approved ROE for that year. The regulatory review will determine the reasons for variance in earnings and could either result in adjustments to the Custom IR plan or a return to cost-of-service regulation.

The EGD and Union Gas amalgamation

On August 30, 2018, OEB issued a decision on the application for the amalgamation of EGD and Union Gas. The OEB major key determinations in the decision are, among others, as follows:

- The OEB allows the Combined Entity to have a deferred rebasing period of five years, which means the next rebasing year application will be expected for 2024 rates. Enbridge had proposed a ten-year period, from 2019 through 2028.
- Annual rate changes during the deferred rebasing period is based on a price cap index (PCI), where PCI growth is driven by an inflation factor less a productivity factor of zero and a stretch factor of 0.3%.
- Earning sharing mechanism is the same as during the current IR plan.
- The Company's proposed Y-factors (flow-through costs) are accepted by the OEB, except for the cap and trade costs, which will be addressed in a separate proceeding.
- Z-factor mechanism threshold is increased to $5.5 million.
- The Company's proposed rate adjustments are accepted as filed.
- The Combined Entity is required to file a cost allocation study in 2019 for the legacy Union Gas service area to consider certain major projects.

DBRS does not expects the OEB key determinations on the amalgamation to have any material impact on the Combined Entity's business risk profile.

Enbridge Gas Distribution Inc.

Balance Sheet (CAD millions)

Assets	June 30 2018	December 31 2017	December 31 2016	Liabilities & Equity	June 30 2018	December 31 2017	December 31 2016
Cash and cash equivalents	6	20	4	Short-term debt	784	960	351
Accounts receivable, net	557	849	655	A/P & accrued liab.	482	662	807
Gas Inventory	353	492	512	Other current liab.	44	43	0
Restricted cash	39	44	58	ST debt - affiliate	34	87	129
Assets held for sale, current	22	15	0	Ltd. due in one year	0	0	500
Due from affiliates	7	43	16	**Current Liabilities**	**1,344**	**1,752**	**1,787**
Total Current Assets	**984**	**1,463**	**1,245**	Long-term debt	3,760	3,760	3,470
Investment in affiliate	825	825	825	LT debt - affiliate	375	375	375
Deferred Amounts and Other Assets	635	597	576	Other liabilities	1,444	1,176	846
Property, plant, and equipment	7,587	7,532	7,418	Deferred income taxes	625	591	532
Assets held for sale, long-term	114	110	0	Preferred Shares	100	100	100
Intangible assets	703	486	158	Common equity	3,200	3,259	3,112
Total Assets	**10,848**	**11,013**	**10,222**	**Total Liab. & Equity**	**10,848**	**11,013**	**10,222**

Balance Sheet and Liquidity Ratios 1

	6 mos. ended June 30 2018	6 mos. ended June 30 2017	6 mos. ended June 30 2018	For the year ended December 31 2017	For the year ended December 31 2016	For the year ended December 31 2015
Net debt in capital structure	60.2%	60.2%	60.2%	60.8%	60.2%	62.0%
Total debt in capital structure	60.2%	60.2%	60.2%	60.9%	60.2%	62.2%
Total debt in capital structure 2	60.2%	60.3%	60.2%	60.9%	60.3%	62.3%
Cash flow/debt	15.4%	13.0%	12.1%	10.3%	11.6%	10.7%
Adjusted cash flow/Total debt 2	15.4%	13.0%	12.1%	10.3%	11.6%	10.7%
Cash flow/Total debt 2	15.4%	13.0%	12.1%	10.3%	11.6%	10.7%
Total debt/EBITDA	5.05	6.28	6.06	7.27	6.79	7.33
(Cash flow - dividend)/Net Capex 3	0.25	0.41	-0.27	-0.15	0.45	0.35
Common dividends/Net income before extras	129.8%	82.4%	260.3%	263.6%	95.1%	89.7%
Common dividends/Cash flow before extras	70.5%	38.4%	134.1%	122.7%	41.3%	42.2%
Coverage Ratios (times) 4						
EBIT interest coverage	3.39	2.38	2.50	2.01	2.03	2.10
EBIT interest coverage 5	3.95	2.79	2.90	2.34	2.36	2.49
EBITDA interest coverage	5.22	4.24	4.21	3.73	3.70	3.76
Cash flow interest coverage	5.05	4.48	4.09	3.80	3.92	3.95
Fixed-charges coverage	3.34	2.35	2.47	1.98	2.00	2.07
Fixed-charges coverage 2	3.34	2.34	2.47	1.98	2.00	2.06

1 DBRS allocates debt and equity equivalents to all preferreds and minority interests. 2 Includes operating leases treated as debt. 3 Capex excludes acquisitions and equity investments. 4 Coverage ratios adjusted to account for the impact of MTM transactions. 5 Excludes interest on affiliate loans.

Rating History

	Current	2017	2016	2015	2014
Issuer Rating	A	A	A	A	A
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

Previous Action

- Confirmed, September 13, 2017.

Commercial Paper Limit

- $1.0 billion.

Previous Report

- Enbridge Gas Distribution Inc.: Rating Report, September 20, 2017.

Notes:
All figures are in Canadian dollars unless otherwise noted.

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Rating Report

Report Date:
January 24, 2012

Previous Report:
January 31, 2011

Insight beyond the rating.

Union Gas Limited

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The Company

Union Gas Limited is a utility that provides natural gas distribution and transmission and storage services in southwestern, northern and eastern Ontario, serving approximately 1.35 million customers. It is a direct, wholly owned subsidiary of Westcoast Energy Inc. (rated A (low), Stable), which is indirectly owned by Spectra Energy Capital, LLC (rated BBB (high), Stable).

Commercial Paper Limit

$400 million

Rating

Debt	**Rating**	**Rating Action**	**Trend**
Unsecured Debentures/Medium-Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating Update

DBRS has confirmed the ratings of the Unsecured Debentures/Medium-Term Note Debentures, the Commercial Paper and the Cumulative Redeemable Preferred Shares of Union Gas Limited (Union or the Company) at "A," R-1 (low) and Pfd-2, respectively, all with Stable trends. The confirmations reflect relatively stable earnings contributions from Union's regulated businesses (i.e., gas distributions, regulated storage and gas transmission), which accounted for the majority of consolidated earnings, and Union's reasonable credit profile.

Union's financial performance continued to benefit from the continued expansion of higher-margin non-regulated natural gas storage facilities, offset by higher cost-cutting pressure in the regulated business (as a result of Union's regulatory regime having changed from a cost-of-service (COS) system to an incentive regulation (IR) framework in 2008). However, DBRS is concerned about rising non-regulated business exposure, affecting Union's overall business risk profile and increasing earnings volatility. Non-regulated earnings increased from 10% in 2008 to more than 20% in 2010 (DBRS estimate) and are expected to continue to rise over the medium term. DBRS views the Company's current 64% debt level target as rather high, given its rising non-regulated business exposure. DBRS notes that the Company has filed a rate case for the 2013 rebasing, asking for a 40% deemed equity (currently 36%). If its request is granted, DBRS expects Union to manage its balance sheet in line with the new regulatory capital structure and maintain greater financial flexibility, commensurate with the current rating category.

The IR framework creates uncertainty in the regulated business that did not exist under the COS system. Earnings from the regulated distribution business are under cost-saving pressure with the IR framework. Union is required to continue to identify cost-saving opportunities to overcome the productivity factor of 1.82% to improve its earnings. In addition, the Company is required to continue to manage its capital program effectively within its regulatory limits during the IR period since any extra capital investment as a result of its aging infrastructure may not be recovered in a timely fashion, which could weaken its credit metrics.

Rating Considerations

Strengths

(1) Reasonable regulatory environment
(2) Large customer base and strong service area
(3) Reasonable credit metrics
(4) Additional earnings growth from storage facilities

Challenges

(1) Volume risk and decline in customer usage
(2) Expansion in unregulated businesses
(3) Low allowed return on equity (ROE)
(4) Consistent free cash flow deficits

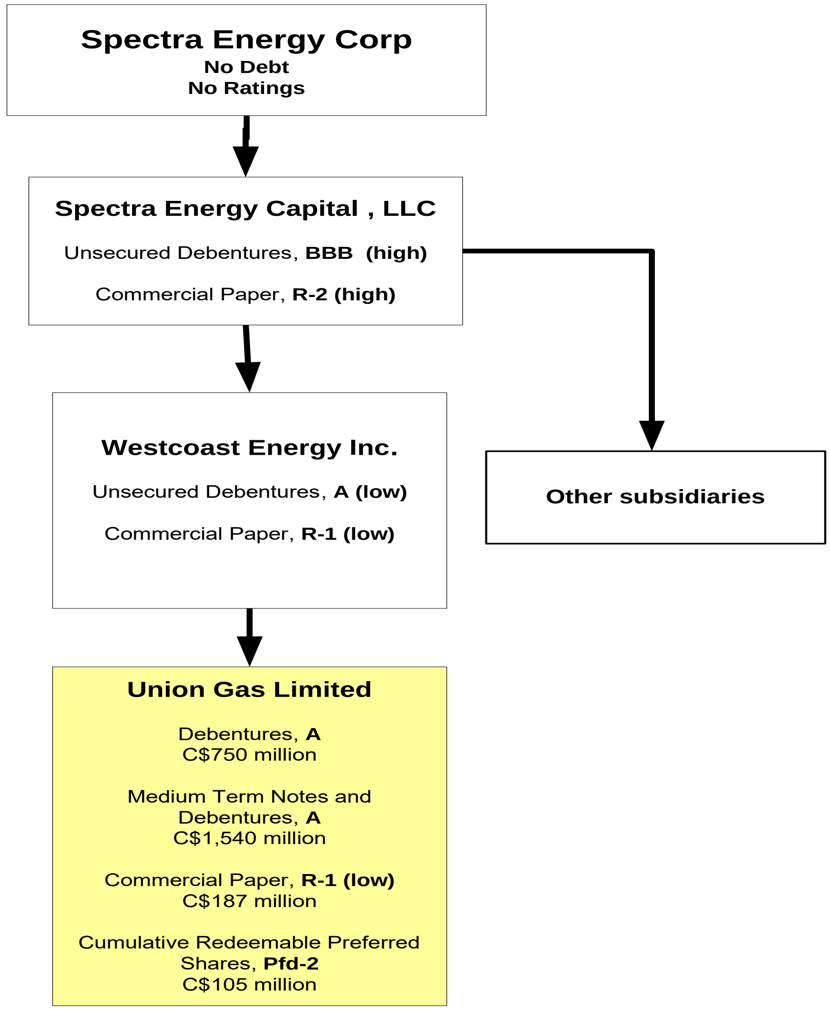
Financial Information

Union Gas Limited	LTM Sep. 30	For the year ended December 31				
(C$ millions where applicable)	2011	2010	2009	2008	2007	2006
EBIT-interest coverage	2.74x	2.56x	2.41x	2.47x	2.24x	1.90x
Fixed-charges coverage	2.68x	2.53x	2.36x	2.35x	2.13x	1.81x
Debt/Capital	61.6%	64.1%	61.0%	64.1%	61.6%	63.4%
Cash flow/Debt	15.6%	16.6%	14.0%	14.6%	14.7%	7.8%
Cash flow/Capex	1.31x	1.85x	1.28x	0.92x	0.87x	0.50x
Approved ROE	8.54%	8.54%	8.54%	8.54%	8.54%	9.63%
Net Income before non-recurring items	215	206	177	177	140	102
Cash flow from operations	385	429	315	372	323	171

Union Gas Limited

Report Date:
January 24, 2012

Organizational Chart



As of September 30, 2011.

Union Gas Limited

Report Date:
January 24, 2012

Rating Considerations Details

Strengths

(1) **Reasonable regulatory environment:** Union's gas distributions are in a stable and reasonable regulatory environment, which allows it to recover prudently incurred capital expenditures and earn a reasonable return on its investments. The Company currently has a five-year agreement under the IR framework (the Agreement) to the end of 2012. Under the Agreement, the Company may not recover operating costs that are not covered by the formula specified in the Agreement. However, DBRS still views Ontario's IR framework as reasonable as it provides Union with an incentive to improve its earnings beyond the allowed ROE and maintain reasonably stable cash flow.

(2) **Large customer base and strong service area:** Union's cash flow is supported by a large customer base (1.35 million) as it is one of the largest natural gas distributors in Canada and provides distribution, storage or transportation services to most gas-fired generation plants in Ontario. Moreover, the Company's service area covers more than 400 communities in northern, southwestern and eastern Ontario. Approximately 45% of this customer base is residential, which is less exposed to economic conditions.

(3) **Reasonable credit metrics:** For the 12 months ending September 30, 2011 (LTM 2011), Union's debt leverage ratio (61.1%), EBIT interest coverage (2.74 times (x)) and cash flow-to-debt ratio (15.6%) remained appropriate for its rating parameters. Union is committed to maintaining its common equity level in line with the 36% level approved by the Ontario Energy Board (OEB). Given Union's debt leverage strategy and the move to the IR framework, DBRS expects the Company to maintain EBIT interest coverage above 2.2x and cash flow-to-debt above 14.5%.

(4) **Additional earnings growth from storage facilities:** Union's Dawn storage facility (50 billion cubic feet of capacity) is the largest natural gas storage facility in Canada and is strategically connected to key pipelines that allow Union to transmit natural gas to other major Canadian and U.S. markets. The Company's continued expansion of its unregulated storage capacity is expected to provide additional earnings growth potential over the medium term and enable the Company to better manage gas inventory, thereby increasing operational flexibility.

Challenges

(1) **Volume risk and decline in customer usage:** Union is exposed to a degree of demand risk since its rates are based on forecast volumes, which are sensitive to changes in weather, economic conditions, natural gas prices and declines in customer usage. In addition, Union is experiencing a reduction in distribution throughput from energy conservation initiatives and the negative impact of the recent economic recession. This is partially mitigated by low natural gas prices, which support its competitiveness relative to other energy sources.

(2) **Expansion into unregulated business:** Union's intention to expand its unregulated storage segment may result in higher earnings volatility as DBRS views this segment as higher risk than the distribution business and the regulated storage business. Currently, the unregulated portion of Union's storage business comprises approximately one-third of its storage capacity, which is manageable.

(3) **Low allowed ROE:** Union is allowed to earn a fixed ROE of 8.54% for the 2008–2012 period, which is relatively weak compared with that of other utilities in Ontario. While the IR framework provides the Company with an incentive to earn higher returns than the allowed ROE, up to 200 basis points (bps), earnings levels greater than 200 bps will have to be shared with ratepayers on a 50/50 basis.

(4) **Cash flow deficits:** Union generated negative free cash flow (before working capital) in most years. Deficits for LTM 2011 were mainly due to higher dividends paid to the parent in 2010 (the cash flow surplus for the nine months ending September 2011 was due to a substantial reduction in dividends). These deficits have been largely financed with debt issuance. DBRS expects the Company to continue to manage its dividend policy in such a way as to maintain the debt leverage below or at the deemed equity of 36%.

Regulation

Regulatory Overview

Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB.

Gas Distribution

Union's distribution rates are set under the Agreement, which expires by the end of 2012. The Agreement was approved by the OEB on January 17, 2008, with the associated annual rate changes implemented on April 1, 2008. Key elements of the Agreement include the following:

- Allowance for inflationary rate increases based on the consumer price index (CPI), offset by a productivity factor of 1.82% that is fixed for the duration of the Agreement.
- Allowance for additional rate adjustments in the small-volume customer classes to reflect the decline in the three-year average use per customer. A new deferral account was also established to capture declines in the variance between forecast and actual use per customer.
- Continued pass-through of gas commodity (adjusted quarterly), upstream transportation and demand-side management costs.
- An allowance for unexpected, prudent cost changes that are outside of management's control. These costs must not already be in the pricing formula in the Agreement.
- Allowed ROE of 8.54% fixed through 2012. An earnings sharing mechanism between the Company and its ratepayers stipulates that if, in any calendar year, the Company's actual gas distribution ROE is more than 200 bps above the allowed ROE, excess earnings will be shared 50/50 between Union and its customers.
- The deemed equity component also remains at 36% throughout the Agreement.
- In December 2009, the OEB issued a policy report, determining that Union's ROE should increase by 129 bps, which is expected to be incorporated in its application for 2013 rates.
- The current gas cost deferral accounts, storage accounts and other deferral accounts remain in place.
- The Agreement also provides that, in the event ROE is 300 bps below the allowed level, Union could file for relief.
- Pursuant to a subsequent agreement (2009), any earnings exceeding the 300 bps limit will have to be shared with the ratepayers on a 90/10 basis in favour of the ratepayers.
- The Company filed its 2013 rate application at the end of 2011; it is pending a hearing before the OEB.

Gas Storage

- On November 7, 2006, the OEB issued the decision that it would not regulate the price of storage services to customers outside Union's franchise area or of new storage services to customers in the franchise area.
- However, existing customers (representing two-thirds of its storage capacity) in the Company's franchise area continue to be charged at COS rates. The OEB decision also required Union to share long-term storage margins with ratepayers over a four-year phase-out period, which started in 2007 and ended in 2011.
- Given Union's large storage capacity and current strong gas fundamentals, the unregulated storage segment of its business allows Union to earn more profit from customers outside its franchise area and new customers in its franchise area.
- However, this upside is somewhat tempered by higher potential risk as rates for unregulated storage are market based, which makes them more volatile than COS rates. Presently, the unregulated portion of Union's storage business comprises approximately one-third of its total storage capacity.

Union Gas Limited

Report Date:
January 24, 2012

Earnings and Outlook

Income Statement (C$ millions)	9-months ended Sep. 30/11	Sep. 30/1o	LTM Sep. 30/11	For the year ended December 31 2010	2009	2008	2007
Gas Distribution Revenue (net)	518	496	721	699	658	675	655
Storage and Transportation Revenues	233	230	311	308	299	244	215
Ancillary Revenue	21	23	27	29	36	34	37
Operating Revenue	772	749	1,059	1,036	993	953	907
Total operating expenses	480	471	640	631	608	587	567
EBITDA	448	428	625	605	580	552	514
EBIT	292	278	419	405	385	366	340
Net Interest Expense	112	117	153	158	160	148	152
Income Taxes	43	33	51	41	48	41	48
Net Income (before extra. & pref divs)	137	128	215	206	177	177	140
Extraordinary Items gain/(loss)	0	0	0	0	2	(3)	5
Preferred Dividends	2	2	2	2	2	5	5
Net Income Available to Common	135	126	213	204	173	169	140
EBIT Margin (net of Cost of Gas)	37.8%	37.1%	39.6%	39.1%	38.8%	38.4%	37.5%
Return on Common Equity	13.2%	12.6%	15.3%	15.5%	13.4%	13.8%	11.6%

Summary

- Union's earnings are principally from regulated gas distribution, regulated storage and transmission and unregulated storage (DBRS estimates that the current net unregulated earnings account for more than 20% of total earnings, up from 10% in 2008).
- Earnings in 2010 were higher than 2009, mainly as a result of the following factors:
  - A significant reduction in operating fuel costs (down $31 million).
  - Increases in transmission services and in long-term storage services.
  - A modest growth in new customers.
  - Higher earnings were offset: (1) by warmer weather in 2010 compared to 2009, which resulted in higher usage and; (2) higher pension costs.
- Earnings for the nine months ending September 30, 2011, were higher than the same period in 2010 mainly as a result of the following factors:
  - Colder weather (15% colder than the first nine months of 2010).
  - New customers (a $11 million increase in revenue).
  - Higher employee benefit costs offset the earnings increase.

Outlook

- DBRS anticipates that earnings from Union's gas distribution segment will remain relatively stable through 2012 until the next rate application has been settled.
- Although weather conditions are unpredictable, DBRS expects ongoing energy conservation programs, including the Company's Demand Side Management (DSM) initiative, to have a modest impact on customer usage, which should be offset by modest customer growth.
- Long-term earnings from unregulated storage are expected to increase, reflecting demand growth from gas-fired power generation in Union's service area and the Company's intention to expand the storage business.

Union Gas Limited

Report Date:
January 24, 2012

Financial Profile

Cash Flow Statement	9-months ended		LTM	For the year ended December 31			
(C$ millions)	Sep. 30/11	Sep. 30/1o	Sep. 30/11	2010	2009	2008	2007
Net Income (before extras. & after prefs.)	135	126	213	204	175	172	135
Depreciation & Amortization	156	149	207	200	195	187	176
Non-Cash Charges & Deferred Income Taxes	(6)	54	(35)	25	(55)	13	12
Cash Flow From Operations	285	329	385	429	315	372	323
Dividends to Parent	(49)	(165)	(190)	(306)	(50)	(120)	(36)
Capital Expenditures	(194)	(131)	(295)	(232)	(247)	(404)	(373)
Free Cash Flow Before W/C	42	33	(100)	(109)	18	(152)	(86)
Change in Working Capital	65	(211)	19	(257)	327	(218)	(29)
Net Free Cash Flow	107	(178)	(81)	(366)	345	(370)	(115)
Acquisitions/Divestitures	0	0	0	0	0	0	(7)
Other	0	0	0	0	0	0	0
Cash Flow before Financing	107	(178)	(81)	(366)	345	(370)	(122)
Net Change in Debt Financing	(118)	144	82	344	(311)	362	13
Net Change in Preferred Equity Financing	0	0	0	0	0	0	0
Net Change in Common Equity Financing & Othe	0	0	0	0	0	0	0
Net Change in Cash	(11)	(34)	1	(22)	34	(8)	(109)

Key Ratios	For 9-months ended		LTM	FYE Dec. 31st			
(C$ millions)	Sep. 30/11	Sep. 30/10	Sep. 30/11	2010	2009	2008	2007
Total Debt	2,468	2,388	2,468	2,588	2,245	2,555	2,195
Debt/Capital	61.6%	61.3%	61.6%	64.1%	61.0%	64.1%	61.6%
EBIT/Interest Expense	2.61x	2.38x	2.74x	2.56x	2.41x	2.47x	2.24x
Cash Flow/Total Adj. Debt	15.4%	18.4%	15.6%	16.6%	14.0%	14.6%	14.7%
Fixed-Charge Coverage	2.54x	2.31x	2.68x	2.53x	2.36x	2.35x	2.13x

Summary

- Overall, free cash flow (before working capital) was negative in most years, reflecting higher capex prior to 2009 and a substantial increase in dividends in 2010.
- Capex in 2010 and 2011 in the gas distribution business was largely used to maintain system reliability.
- Significant working capital fluctuations largely reflect variances in gas cost deferral accounts.
- Union financed deficits largely with debt.
- Dividends are primarily used to manage Union's capital structure at regulatory-approved levels (64% debt and 36% equity). Capex was reduced significantly in 2011, enabling the Company to use free cash flow to reduce the debt by $118 million, improving the debt-to-capital ratio to a reasonable level at 61.6%.
- The Company's interest coverage and cash flow ratios (LTM 2011) at 2.74x and 15.6%, respectively, were reasonably in line with the "A" rating category.

Outlook

- DBRS expects Union to continue to generate negative free cash flow over the near to medium term as capex increases from the 2010 level and its dividend policy maintains the debt leverage in line with the regulatory capital structure in the rate base.
- In 2012, capex is expected to exceed depreciation by approximately 30%, which is considered normal. DBRS expects extra capex (above the deprecation amount) in the regulated businesses to be added to the rate base in the re-basing year.
- Debt levels are expected to increase as the Company continues to finance cash shortfalls with debt. DBRS expects the debt leverage ratio to return to the 64% level in the medium term, which DBRS views as rather high for the current rating.
- Given the Company's debt leverage strategy and the move to the IR framework, DBRS expects Union to maintain its EBIT interest coverage above 2.2x and cash flow-to-debt ratio above 14.5%, which are in line with the current rating.

Liquidity and Long-Term Debt Maturities

Liquidity

Credit Facility*	As at September 30, 2011			
(C$ millions)	Maturity Date	Committed	CP	Available
Five-year syndicated credit facility	Jul. 2012	500	187	313
Total		500	187	313

- In December 2011, the five-year syndicate credit facility was reduced to $400 million from $500 million, maturing in December 2016. All the terms and conditions in the new facility remained unchanged.
- DBRS views Union's liquidity as sufficient for its working capital funding requirements. Union's $400 million five-year committed credit facility expires in July 2012 and is used to backstop the Company's $400 million commercial paper program.
- The facility contains a maximum 75% debt-to-capital covenant and includes a provision that requires the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year.
- Union is generally subject to seasonality as a part of its business and as a result, its short-term debt (because of the need from more liquidity) and its gas inventory typically peak in the first and fourth quarters of every year.

Debt Maturity

Debt Maturity (C$ millions)	2012	2013	2014	2015	2016	2016+	Total
MTNs and Debentures	0	0	150	150	200	1,776	2,276

- The Company's debt maturity is well spread out, with no long-term debt due in 2012 and 2013, and the amounts due in 2014 and 2015 remain modest and within the financing capacity of the Company.
- The $500 million shelf prospectus, maturing in October 2012, contains a 75% maximum total debt-to-capitalization issuance covenant; in addition, any incremental debt is also subject to an interest coverage test of 2.0x. As at September 30, 2011, the Company was in compliance with all covenants.
- In June 2011, the Company issued $300 million in medium-term notes (MTNs; Series 9, 4.88%, due 2041) to refinance the $250 million MTNs due in May 2011 and for general corporate purposes.

Long-Term Debt

Long-term debt as at September 30, 2011*		
(C$ millions)	Coupon	Amount
Medium-Term Notes/Debentures		
Series 5, due June 2016	4.64%	200
Series 6 to Series 9 due 2018-2041	4.85%-6.05%	1,340
Other Debentures		
1994 Series due February 2014	7.90%	150
1990 Series due August 2015	11.50%	150
1992-1995 Series due 2017-2025	8.65%-9.70%	450
		2,290
Less: Deferred financing charges		14
Total long -term debt		2,276
Short-term debt (commercial papers)		187
Total debt as at September 30, 2011		**2,463**

* DBRS estimates based on the Company's 2010 Annual report and Q3 report

Union Gas Limited

Report Date:
January 24, 2012

Union Gas Limited

Balance Sheet *(C$ millions)*

Assets	As at Sep. 30/11	As at December 31st 2010	2009	Liabilities & Equity	As at Sep. 30/11	As at December 31st 2010	2009
Cash	1	12	34	Short-Term Debt	187	355	39
Accounts Receivable	432	516	401	A/P & Accrued Charges	670	590	873
Inventories	288	174	224	LT Debt Due in One Year	0	250	222
Other	16	14	57	**Current Liabilities**	857	1,195	1,134
Current Assets	737	716	716	Long-Term Debt	2,276	1,978	1,979
Net fixed assets	4,436	4,376	4,303	Def'd Income Taxes & Others	991	956	890
Other	493	493	427	Debt Equiv. Pref.	5	5	5
				Preferred Equity	105	105	105
				Non-Controlling Interest	9	9	10
				Shareholders Equity	1,423	1,337	1,323
Total	5,666	5,585	5,446	**Total**	5,666	5,585	5,446

Ratio Analysis

	LTM Sep. 30 2011	For the year ended December 31 2010	2009	2008	2007	2006	2005
Liquidity Ratios							
Current Ratio	0.86x	0.60x	0.63x	0.84x	0.58x	0.96x	1.02x
Cash Flow/Total Debt	15.6%	16.6%	14.0%	14.6%	14.7%	7.8%	13.7%
Cash Flow/Capital Expenditures	1.31x	1.85x	1.28x	0.92x	0.87x	0.50x	1.27x
Cash Flow-Dividends/Capital Expenditures[1]	0.66x	0.53x	1.07x	0.62x	0.77x	0.36x	0.77x
Debt/Cap	61.6%	64.1%	61.0%	64.1%	61.6%	63.4%	64.0%
Deemed Common Equity	36.0%	36.0%	36.0%	36.0%	36.0%	35.0%	35.0%
Dividend Payout[1]	89.2%	150.0%	28.6%	69.8%	26.7%	50.5%	100.0%
Debt/EBITDA	3.95x	4.28x	3.87x	4.63x	4.27x	4.80x	4.44x
Coverage Ratios[2]							
EBIT/Interest Expense	2.74x	2.56x	2.41x	2.47x	2.24x	1.90x	2.09x
EBITDA/Interest Expense	4.08x	3.83x	3.63x	3.73x	3.38x	2.95x	3.09x
Fixed-Charge Coverage	2.68x	2.53x	2.36x	2.35x	2.13x	1.81x	1.99x
Earnings Quality/Operating Efficiencies & Statistics							
Operating margin	39.6%	39.1%	38.8%	38.4%	37.5%	35.4%	38.5%
Net margin (bef. extras., after preferred divs)	20.1%	19.7%	17.6%	18.0%	14.9%	11.7%	13.6%
Return on avg. common equity	15.3%	15.5%	13.4%	13.8%	11.6%	9.1%	10.9%
Approved ROE	8.54%	8.54%	8.54%	8.54%	8.54%	9.63%	9.62%
Degree day deficiency – % normal	102%	106.8%	97.7%	97.8%	105.4%	115.9%	103.5%
Customer growth	1.3%	1.4%	1.2%	1.6%	1.7%	1.5%	2.0%

(1) Special dividends were paid to maintain capitalization within regulated limits in 2008 and 2005.
(2) Before capitalized interest, AFUDC, and debt amortizations.

	9m-2011	2010	2009	2008	2007	2006	2005	2004
Actual heating degree days (Celcius)	2,749	3,796	4,130	4,161	3,928	3,605	4,041	4,126
Normal heating degree days (Celcius)	2,690	4,056	4,034	4,070	4,139	4,178	4,182	4,171
Customers (Thousands)	1,352	1,344	1,325	1,309	1,289	1,268	1,249	1,224

Union Gas Limited

Report Date:
January 24, 2012

Rating

Debt	Rating	Rating Action	Trend
Unsecured Debentures/Medium Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating History

	Current	2011	2010	2009	2008	2007
Unsecured Debentures/ Medium-Term Note Debentures	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cumulative Redeemable Preferred Shares	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Notes:
All figures are in Canadian dollars unless otherwise noted.

Rating Report

Report Date:
April 29, 2013

Previous Report:
September 18, 2012

Insight beyond the rating.

Union Gas Limited

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The Company

Union Gas Limited is a utility that provides natural gas distribution, transmission and storage services in southwestern, northern and eastern Ontario, serving approximately 1.4 million customers. It is a direct, wholly owned subsidiary of Westcoast Energy Inc. (rated A (low), Stable), which is indirectly owned by Spectra Energy Capital, LLC (rated BBB (high), Stable).

Commercial Paper Limit

$400 million

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures/Medium-Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating Update

DBRS has confirmed the ratings of Union Gas Limited (Union or the Company) as listed above. The rating confirmations reflect the relative stability of earnings from Union's regulated businesses (i.e., gas distributions, regulated storage and gas transmission), which accounted for the majority of consolidated earnings, and Union's reasonable credit profile.

In the Ontario Energy Board's (OEB) Decision for Union's 2013 cost-of-service (COS) application, the OEB approved a return on equity (ROE) of 8.93% (8.54% in 2012) and equity thickness of 36%. Rates are expected to increase in 2013 and have an impact of around 0% to 6% on the average annual total bill, depending on customer location and class. In addition, the OEB found that revenues associated with the optimization of upstream transportation contracts, effective in 2013, are to be considered a reduction of natural gas supply costs, 90% of which are to be credited to customers. As a result, 2012 earnings decreased due to this treatment and around $34 million will be refunded to customers. The OEB also had similar findings in November 2012 for 2011 upstream transportation optimization revenues (refund of $5 million). Union has appealed the November 2012 decision with the Ontario Divisional Court and a hearing and decision is expected by the end of 2013. The Decisions had no rating implications as the regulatory framework remained reasonable.

Union's financial performance continued to benefit from the ongoing expansion of higher-margin non-regulated natural gas storage facilities. However, DBRS is concerned about its rising exposure to the non-regulated business, which affects Union's overall business risk profile and increases potential earnings volatility. Non-regulated earnings increased to approximately 15% in 2012 (DBRS estimate) from 10% in 2008 and are expected to continue to rise over the medium term. The Company is expected to continue to generate free cash flow deficits over the medium term as a result of expansions and upgrades. DBRS expects the Company to finance free cash flow deficits through managing dividends and issuing debt in a prudent manner that will maintain its debt-to-capital ratio within DBRS's "A" rating range.

Rating Considerations

Strengths

(1) Reasonable regulatory environment
(2) Large customer base and strong service area
(3) Reasonable credit metrics
(4) Additional earnings growth from storage facilities

Challenges

(1) Volume risk and decline in customer usage
(2) Expansion in unregulated businesses
(3) Consistent free cash flow deficits
(4) Limited access to equity markets

Financial Information

	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
Union Gas Limited	**For the year ended December 31**				
(CA$ millions where applicable)	**2012**	**2011**	**2010**	**2009**	**2008**
EBIT gross interest coverage (times)	2.35	2.69	2.55	2.35	2.36
Total debt in capital structure (1)	64.2%	63.4%	64.3%	61.3%	64.2%
Cash flow/Total debt	14.0%	15.5%	16.7%	14.1%	14.9%
Net income before non-recurring items	170	201	206	175	180
Cash flow from operations	375	414	431	315	380

(1) Adjusted for operating leases and accumulated other comprehensive income.

Rating Considerations Details

Strengths

(1) **Reasonable regulatory environment.** Union's gas distribution business operates in a reasonable regulatory environment, which allows it to recover prudently incurred capital expenditures (capex) and earn a reasonable return on its investments. The Company is operating under the COS framework in 2013, which allows it to rebase its rates, and will operate under an incentive regulation (IR) framework in 2014 and beyond.

(2) **Large customer base and strong service area.** Union's cash flow is supported by a large customer base (1.4 million), as it is one of the largest natural gas distributors in Canada and provides distribution, storage or transportation services to most gas-fired generation plants in Ontario. Moreover, the Company's service area covers more than 400 communities in northern, southwestern and eastern Ontario. Approximately 45% of revenue is generated from residential customers, a segment less exposed to economic conditions.

(3) **Reasonable credit metrics.** For the 12 months ended December 31, 2012, Union's debt leverage ratio (64.2%), EBIT interest coverage (2.35 times (x)) and cash flow-to-debt ratio (14.0%) remained reasonable for its "A" rating. Union is committed to maintaining its common equity level, for the regulatory portion, in line with the approved equity of 36% by the OEB.

(4) **Additional earnings growth from storage facilities.** Union's Dawn storage facility (50 billion cubic feet of capacity) is the largest natural gas storage facility in Canada and is strategically connected to key pipelines that allow Union to transmit natural gas to other major Canadian and U.S. markets. The Company's continued expansion of its unregulated storage capacity as well as the change in traditional natural gas flow patterns is expected to provide additional earnings growth potential over the medium term.

Challenges

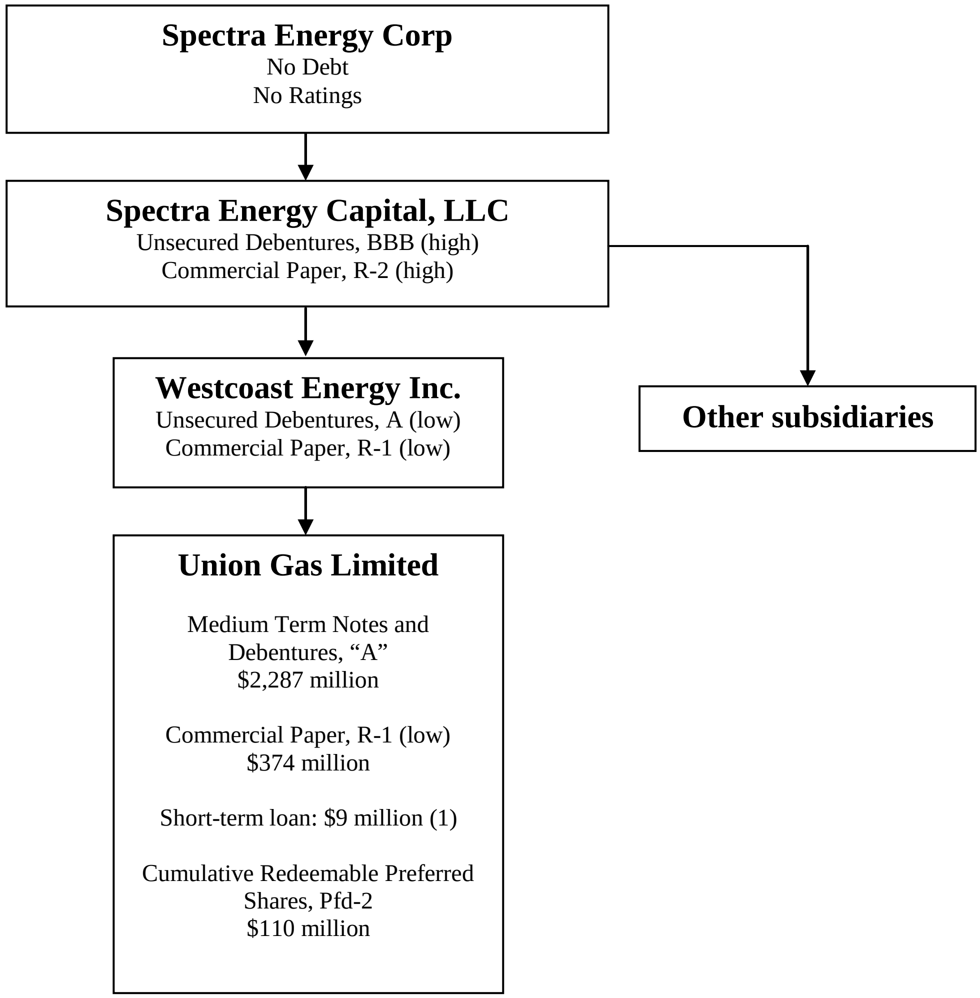
(1) **Volume risk and decline in customer usage.** Union is exposed to a degree of demand risk, since its rates are based on forecast volumes, which are sensitive to changes in weather, economic conditions, natural gas prices and declines in customer usage. Union is experiencing a reduction in distribution throughput due to energy conservation initiatives, declining normalized use per customer and warmer-than-expected weather conditions. This reduction is partially offset by lower natural gas prices, which support its competitiveness relative to other energy sources, and greater role for natural gas-fired generation plants in Ontario.

(2) **Expansion into unregulated business.** Union's intention to expand its unregulated storage segment may result in higher earnings volatility, as DBRS views this segment as higher risk than the regulated distribution and storage businesses. Currently, the unregulated portion of Union's storage business comprises approximately one-third of its storage capacity, which is a manageable level.

(3) **Consistent free cash flow deficits.** Union generated free cash flow deficits for the past five years and this is expected to continue in the medium term due to higher capex for storage and gas transmission projects. DBRS expects the Company to finance the deficits by managing dividends and issuing new debt in a prudent manner to maintain its debt-to-capital ratio within DBRS's "A" rating range.

(4) **Limited access to equity markets.** Union is a wholly owned subsidiary of Westcoast Energy Inc. (rated A (low)), which is indirectly owned by Spectra Energy Corp. This ownership structure limits Union's ability to access the equity markets directly. As a result, additional cash flow needs are largely financed through retaining earnings and issuing debt.

Organizational Chart (as of December 31, 2012)



(1) This is an intercompany loan from Westcoast Energy Inc.

Regulation

Regulatory Overview

Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB.

Gas Distribution

- Union's distribution rates are set under a multi-year IR framework with rebasing under the COS framework between the IR periods.
- From 2008 to 2012, Union's rates were set under the IR framework.
- Union filed an application with the OEB in November 2011 to set its distribution rates effective January 1, 2013, under the COS framework.
- A settlement agreement for the application was reached and accepted by the OEB on July 10, 2012. For the unsettled issues, the OEB issued its decision on October 25, 2012.
- Among other things, the OEB approved rate increases that have an average annual impact on a customer's total bill of around 0% to 6% depending on the location and class.
  - In January 2013, the OEB approved Union's draft rate order, filed in December 2012. Union implemented the approved OEB rate order in February 2013.
- In addition, the OEB found that the revenues associated with the optimization of upstream transportation contracts effective in 2013 are to be considered a reduction of natural gas supply costs, 90% of which are to be credited to customers.
  - The OEB issued a decision on November 19, 2012, that certain 2011 revenues derived from the optimization of upstream transportation contracts would be refunded to customers as well. Union appealed this decision on the basis of impermissible retroactive ratemaking and a hearing and decision is expected by the end of 2013 by the Ontario Divisional Court.
- For 2013, the company has an approved ROE for 8.93% and a deemed equity component of 36%.
- The Company's gas cost deferral accounts, storage accounts and other deferral accounts remained in place.
- In 2013, the Company intends to apply to the OEB for another IR framework effective for 2014 and beyond.

Gas Storage

- Storage services outside Union's franchise area or new storage services to customers in the franchise area are not regulated by the OEB. This accounts for approximately one-third of storage capacity.
- Storage within Union Gas's service area is regulated under the COS regulation.
- On July 18, 2012, the OEB directed the Company to share short-term storage margins between the ratepayers and Union and to dispose of an incremental credit balance of $3 million to ratepayers. Combined with the 2011 IR earnings sharing ($3 million), a total of $6 million is refundable to customers. The implementation of the refund commenced October 1, 2012.

Earnings and Outlook

(CA$ millions where applicable)	USGAAP 2012	USGAAP 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008
	For the year ended December 31				
Gas distribution margin	727	713	699	658	675
Storage and transportation revenues	269	311	308	299	244
Ancillary revenue	28	34	29	36	34
Operating revenue	1,024	1,058	1,036	993	953
Total operating expense	658	646	631	608	587
EBITDA	579	617	605	580	552
EBIT	366	412	405	385	366
Gross interest expense	156	153	159	164	155
Earning before taxes	210	259	247	223	221
Net income before non-recurring items	170	201	206	175	180
Reported net income	170	201	206	175	180
Return on equity	13.6%	14.9%	14.2%	12.2%	12.8%
Distribution rate base	N/A	3,583	3,570	3,483	3,348

2012 Summary

- Union's earnings are principally generated from its regulated gas distribution, storage and transmission businesses. However, earnings from the unregulated storage business have continued to grow, accounting for over 15% of total earnings in 2012, up from around 10% in 2008 (DBRS estimate).
- Earnings in 2012 were slightly lower than 2011, mainly as a result of the following factors:
  - Decrease in customer usage of natural gas due to warmer weather (10% warmer than 2011).
  - Refund of certain revenues realized from the optimization of upstream transportation contracts to customers, due to a decision from the OEB in November 2012.
  - However, decreases in earnings were partially offset by lower earnings to be shared with customers, customer growth and increase in short-term transportation service.

2013 Outlook

- DBRS anticipates that earnings from Union's regulated gas distribution segment will remain relatively stable in 2013 as decreases in earnings are expected to be offset by modest customer growth and the increased role of natural gas-fired power generators.
- Although weather conditions are unpredictable, DBRS expects ongoing energy conservation programs, including the Company's Demand Side Management Initiative, to have a modest impact on customer usage. This could potentially be offset by modest customer growth.
- Long-term earnings from unregulated storage are expected to increase, reflecting an increase in demand for gas storage in Ontario and the Company's intention to expand the storage business.

Union Gas Limited

Report Date:
April 29, 2013

Financial Profile

(CA$ millions where applicable)	USGAAP 2012	USGAAP 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008
	For the year ended December 31				
Net income before non-recurring items	170	201	206	175	180
Depreciation & amortization	213	205	200	195	187
Deferred income taxes and other	(8)	8	25	(55)	13
Cash flow (bef. working cap. changes)	375	414	431	315	380
Dividends paid	(165)	(147)	(308)	(50)	(120)
Capital expenditures	(271)	(290)	(232)	(247)	(404)
Free cash flow (bef. working cap. changes)	(61)	(23)	(109)	18	(144)
Changes in non-cash work. cap. items	58	(55)	(257)	327	(218)
Net Free Cash Flow	(3)	(78)	(366)	345	(362)
Acquisitions & long-term investments	0	0	0	0	0
Short-term investments	0	0	0	0	0
Proceeds on asset sales	0	0	0	0	0
Net equity change	0	0	0	0	0
Net debt change	5	73	344	(311)	362
Other	0	0	0	0	0
Change in cash	2	(5)	(22)	34	0
Total debt	2,670	2,665	2,583	2,240	2,550
Cash and equivalents	9	7	12	34	0
Total debt in capital structure (1)	64.2%	63.4%	64.3%	61.3%	64.2%
Cash flow/Total debt	14.0%	15.5%	16.7%	14.1%	14.9%
EBIT interest coverage (times)	2.35	2.69	2.55	2.35	2.36
Dividend payout ratio	97.1%	73.1%	149.5%	28.6%	66.7%

(1) Adjusted for operating leases and accumulated other comprehensive income.

2012 Summary

- Cash flow from operations was lower in 2012 due to warmer-than-expected weather and the OEB's decision to refund certain revenues from the optimization of upstream transportation contracts.
- Free cash flow continued to be negative in 2012, reflecting higher dividends and lower cash flow from operations. However, the company had a minor cash flow deficit after accounting for working capital items.
- Capex was lower in 2012 compared to 2011, largely due to the completion of two large multi-year maintenance projects in 2011, partially offset by an increase in customer attachments.
- The dividends are primarily used to maintain Union's capital structure in line with regulatory-approved levels (64% debt and 36% equity since 2008).
- In 2012, key credit metrics remained within DBRS's "A" rating category.

2013 Outlook

- DBRS expects Union to continue to generate modest free cash flow deficits over the near to medium term as capex is expected to remain relatively high. In 2013, Union expects to spend approximately $364 million on expansion projects ($55 million) and maintenance and upgrades of existing pipelines and infrastructure ($309 million; mostly regulated).
- DBRS expects the Company to maintain its debt leverage in line with the "A" rating category in the medium term by managing free cash flow deficits through dividend management and debt issuances.
- The Company expects to maintain its regulatory-approved capital structure of 36% equity and 64% debt for its regulated assets.

Union Gas Limited

Report Date:
April 29, 2013

Liquidity and Long-Term Debt Maturities

Credit Facility				As at December 31, 2012
(CA$ millions)	**Maturity Date**	**Committed**	**CP**	**Available**
Five-year syndicated credit facility	2016	400	374	26
Total		400	374	26

- The Company's credit facility is mainly used to backstop its $400 million commercial paper program.
- DBRS views Union's liquidity as sufficient for its working capital funding requirements.
- Union is generally subject to seasonality as a part of its business and, as a result, its short-term debt and its gas inventory typically peak in the first and fourth quarters of every year ($374 million outstanding in commercial paper as at December 31, 2012).
- The facility contains a maximum 75% debt-to-capital covenant and includes a provision requiring the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. As at December 31, 2012, the Company was in compliance with these covenants.

Debt Maturity (CA$ millions)	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**
MTNs and Debentures	0	150	150	200	125	1,665	2,290

As at December 31, 2012.

- The Company's debt maturity is well spread out, with no long-term debt due in 2013. The amounts due from 2014 to 2017 remain modest and within the financing capacity of the Company.
- The Company filed a new $800 million base shelf prospectus expiring November 11, 2014, which provides for the issuance of medium-term note debentures. The new base shelf prospectus replaces the $500 million base shelf prospectus that expired on October 10, 2012. As at December 31, 2012, the Company has $800 million available for issuance under the new base shelf prospectus.
- Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants. Therefore, the Company can have a maximum total debt-to-capitalization of 75% and any incremental debt is subject to an interest coverage test of 2.0x. As at December 31, 2012, the Company was in compliance with all covenants.

Long-Term Debt		**December 31**	December 31
(CA$ millions)		**2012**	2011
7.90%	1994 Series debentures, due February 24, 2014	**150**	150
11.50%	1990 Series debentures, due August 28, 2015	**150**	150
4.64%	Series 5, due June 30, 2016	**200**	200
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 10, 2025	**75**	75
4.85%	Series 7, due April 25, 2022	**125**	125
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9 due June 21, 2041	**300**	300
		2,290	2,290
Less: unamortized debt discount		**3**	3
		2,287	2,287
Less: current portion		**-**	-
		2,287	2,287

Union Gas Limited

Report Date:
April 29, 2013

Union Gas Limited

Balance Sheet	USGAAP	USGAAP	CGAAP		USGAAP	USGAAP	CGAAP
(CA$ millions)	Dec. 31	Dec. 31	Dec. 31		Dec. 31	Dec. 31	Dec. 31
Assets	2012	2011	2010	**Liabilities & Equity**	2012	2011	2010
Cash & equivalents	9	7	12	S.T. borrowings	383	378	355
Accounts receivable	588	536	516	Accounts payable	685	622	586
Inventories	199	263	174	Current portion L.T.D.	0	0	250
Deferred income taxes & others	14	8	0	Income taxes payable & others	26	26	8
Total Current Assets	810	814	702	**Total Current Liab.**	1,094	1,026	1,199
Net fixed assets	4,567	4,495	4,376	Long-term debt	2,287	2,287	1,978
Future income tax assets	0	0	14	Asset retirement obligations	143	134	123
Regulatory assets & others	406	355	493	Deferred income taxes	352	293	361
				Regulatory liabilities & others	645	686	468
				Minority interest	9	9	9
				Preferred shares	110	110	110
				Common equity	1,143	1,119	1,337
Total Assets	5,783	5,664	5,585	**Total Liab. & SE**	5,783	5,664	5,585

	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
Balance Sheet &	**For the year ended December 31**				
Liquidity & Capital Ratios	**2012**	**2011**	**2010**	**2009**	**2008**
Current ratio	0.74	0.79	0.59	0.58	0.83
Total debt in capital structure	63.9%	63.9%	64.0%	60.9%	64.1%
Total debt in capital structure (1)	64.2%	63.4%	64.3%	61.3%	64.2%
Cash flow/Total debt	14.0%	15.5%	16.7%	14.1%	14.9%
Cash flow/Total debt (1)	13.9%	15.9%	16.5%	13.8%	14.8%
(Cash flow-dividends)/Capex	0.77	0.92	0.53	1.07	0.64
Dividend payout ratio	97.1%	73.1%	149.5%	28.6%	66.7%
Coverage Ratios (times)					
EBIT gross interest coverage	2.35	2.69	2.55	2.35	2.36
EBITDA gross interest coverage	3.71	4.03	3.81	3.54	3.56
Fixed-charges coverage	2.29	2.64	2.50	2.29	2.27
EBIT gross interest coverage (1)	2.35	2.70	2.55	2.36	2.36
Profitability Ratios					
EBITDA margin	56.5%	58.3%	58.4%	58.4%	57.9%
EBIT margin	35.7%	38.9%	39.1%	38.8%	38.4%
Profit margin	16.6%	19.0%	19.9%	17.6%	18.9%
Return on equity	13.6%	14.9%	14.2%	12.2%	12.8%
Return on capital (1)	6.8%	7.6%	8.1%	7.3%	7.3%

(1) Adjusted for operating leases and accumulated other comprehensive income.

Union Gas Limited

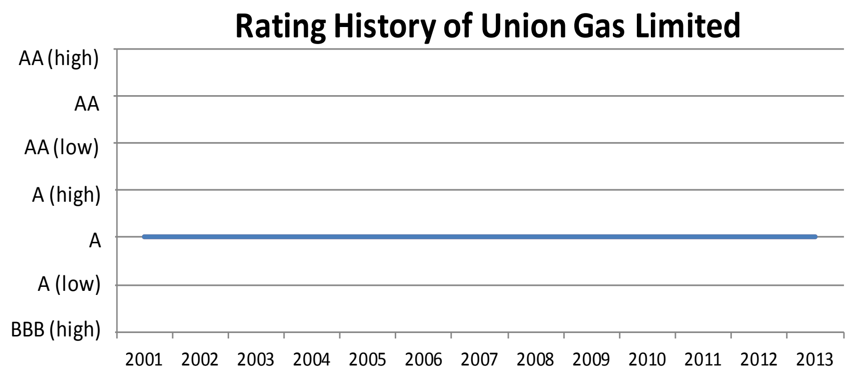
Report Date:
April 29, 2013

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures/Medium-Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating History

	Current	2012	2011	2010	2009	2008
Issuer Rating	A	A	NR	NR	NR	NR
Unsecured Debentures/ Medium-Term Note Debentures	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cumulative Redeemable Preferred Shares	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2



Note:
All figures are in Canadian dollars unless otherwise noted.

Rating Report

Report Date:
February 20, 2014

Previous Report:
April 29, 2013

Union Gas Limited

DBRS
Insight beyond the rating.

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The Company

Union Gas Limited is a utility that provides natural gas distribution, transmission and storage services in southwestern, northern and eastern Ontario, serving approximately 1.4 million customers. Union Gas' common stock is held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (rated A (low)). Westcoast is indirectly owned by Spectra Energy Capital, LLC (rated BBB).

Commercial Paper Limit
$400 million

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures/Medium-Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating Update

DBRS has confirmed the ratings of Union Gas Limited (Union or the Company) as listed above. The rating confirmation reflects DBRS expectation that: (1) Union's low risk regulated gas distribution business will continue to account for the bulk of the Company's earnings (~80% in 2013), providing stability; and (2) the Company will continue to fund capital expenditures while maintaining its key financial metrics.

Union's business risk profile is indicative of an "A" rating based on regulatory and franchise strengths of the Company's natural gas utility business in Ontario (Refer to "Assessment of Union's Regulatory Environment" on page 8). DBRS views the recent five year incentive regulation (IR) framework approved by the Ontario Energy Board (OEB) through a settlement process for 2014-2018 as reasonable due to the following factors: (1) allows the Company to earn a higher return on investment (ROE) than domestic peers on average; (2) provides predictable cash flow as capital expenditures (capex) are pre-approved, subject to certain criteria, for inclusion in the rate base; and (3) annual rate escalation each year at 40% of inflation. DBRS expects the Company to maintain its current financial profile by prudently financing its proposed capital expenditures on expansions and upgrades using a combination of operating cash flow, debt and managing dividend payouts.

In February 2014, the OEB provided regulatory approval for $423 million in capex to expand Union's Dawn to Parkway gas transmission system starting in 2015. The expansion is expected to help grow the rate base and diversify fuel sources, reducing its reliance on supply from Western Canada. The funding of this capex initiative is not expected to result in material deterioration of current credit metrics and remain within regulatory parameters.

One of the key challenges that could impact Union's future ratings is its growing exposure to the higher risk, non-regulated storage business. The confirmation assumes that the future mix between regulated earnings and non-regulated earnings will remain at or close to the current mix of 80%/20%.

Rating Considerations

Strengths	Challenges
(1) Reasonable regulatory environment	(1) Volume risk and decline in customer usage
(2) Large customer base and strong franchise	(2) Growing share of non-regulated business
(3) Stable credit metrics	(3) Consistent free cash flow deficits

Financial Information

Union Gas Limited	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
	9 mos. Sept. 30		12 mos. Sept. 30	For the year ended December 31				
(CA$ millions where applicable)	2013	2012	2013	2012	2011	2010	2009	2008
EBIT gross interest coverage (times)	2.34	2.36	2.33	2.35	2.69	2.55	2.35	2.36
Total debt in capital structure (1)	63.0%	61.8%	63.0%	64.2%	63.4%	64.3%	61.3%	64.2%
Cash flow/Total debt	14.6%	14.7%	14.5%	14.0%	15.5%	16.7%	14.1%	14.9%
Net income before non-recurring items	127	123	174	170	201	206	175	180
Cash flow from operations	296	278	393	375	414	431	315	380

(1) Adjusted for operating leases and accumulated other comprehensive income.

Rating Considerations Details

Strengths

(1) Reasonable regulatory environment. Union's gas regulated distribution business operates under a reasonable regulatory environment, which allows it to recover prudently incurred capital expenditures (capex) and earn a reasonable return on its investments. The Company currently operates under a five-year incentive regulation (IR) framework (2014 to 2018) with rebasing under the cost-of-service (COS) framework in between. Union's regulated distribution business is not exposed to commodity price risk as gas supply costs are adjusted quarterly and passed through to customers.

(2) Large customer base and strong franchise. Union's cash flow is supported by a large customer base (1.4 million), which is growing at a steady rate of ~2%, making it one of the largest natural gas distributors in Canada. Union provides transportation and storage services to almost all, and distribution to most, gas-fired generation plants in Ontario. Moreover, the Company's franchise area covers more than 400 communities in northern, southwestern and eastern Ontario. Approximately 50% of its revenue is generated from residential customers, a segment that is less exposed to economic conditions.

(3) Reasonable credit metrics. For the 12 months ended September 30, 2013, Union's debt leverage ratio (63.0%), EBIT interest coverage (2.33 times (x)) and cash flow-to-debt ratio (14.5%) remained reasonable for its "A" rating. Union is committed to maintaining its capital structure for the regulated operations in line with the approved capital structure of 64% debt and 36% equity.

(4) Additional earnings growth from storage facilities. Union's Dawn storage facility (Approximately 155 billion cubic feet of capacity) is the largest natural gas storage facility in Canada and is strategically connected to key pipelines that allow Union to transmit natural gas to other major Canadian and U.S. markets. Changes in traditional natural gas flow patterns are expected to provide additional earnings growth potential over the medium term.

Challenges

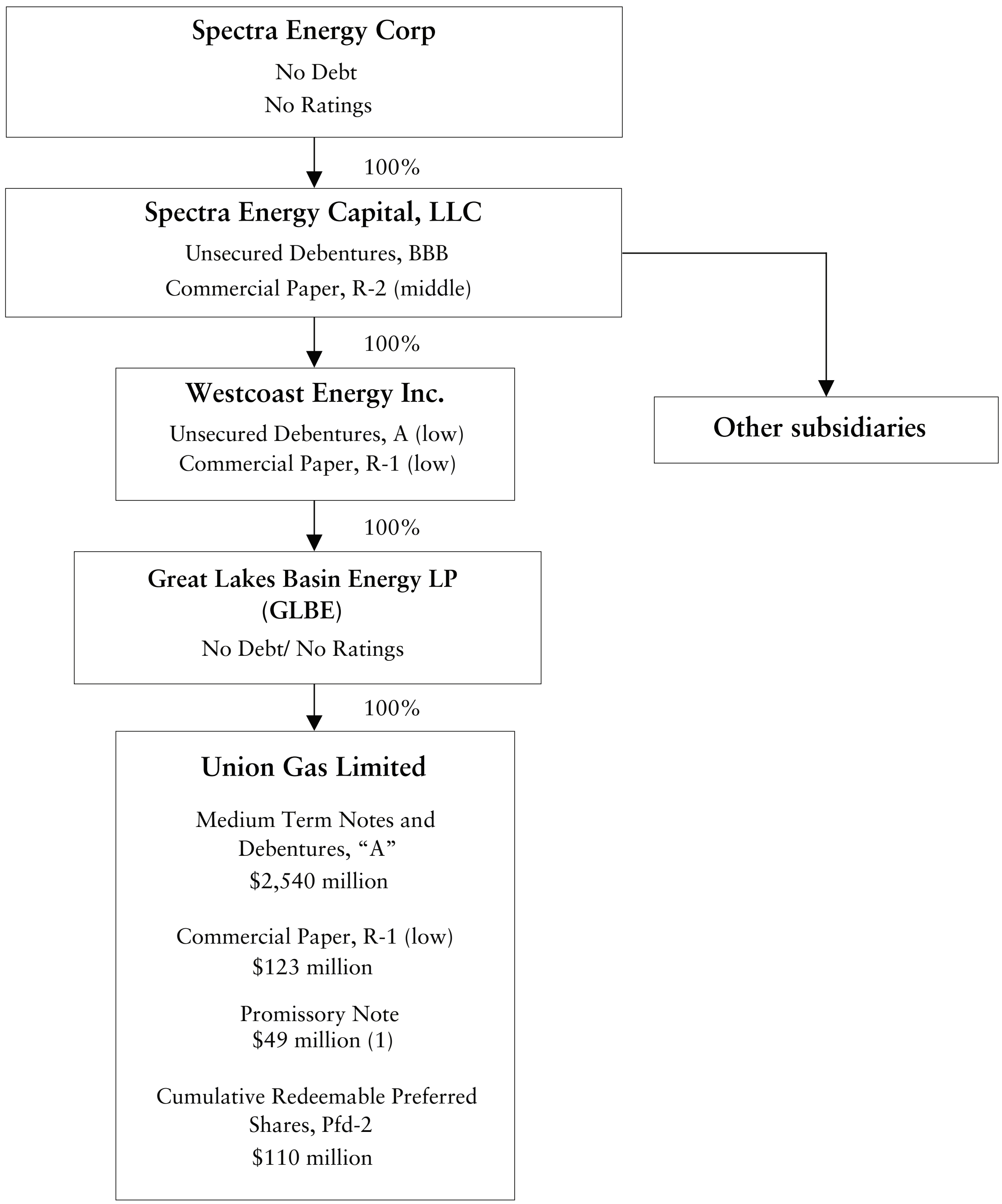
(1) Volume risk and decline in customer usage. Union is exposed to a degree of demand risk, since its rates are based on forecast volumes, which are sensitive to changes in weather, economic conditions, natural gas prices and declines in customer usage. Union is experiencing a reduction in distribution throughput due to energy conservation initiatives, declining normalized use per customer and warmer-than-expected weather conditions. This reduction is partially offset by lower natural gas prices, which support its competitiveness relative to other energy sources, and greater role for natural gas-fired generation plants in Ontario.

(2) Growing share of non-regulated business. Union's non-regulated storage revenues may result in higher earnings volatility, as DBRS views this segment as higher risk than the regulated distribution and storage businesses. In 2012 the non-regulated portion of Union's storage business accounted for approximately 20% of EBIT (14% in 2008).

(3) Consistent free cash flow deficits. Union generated free cash flow deficits for the past five years and this is expected to continue in the medium term due to higher capex for storage and gas transmission projects. DBRS expects the Company to finance the deficits by managing dividends and issuing new debt in a prudent manner to maintain its debt-to-capital ratio within the regulatory levels.

(4) Limited access to equity markets. Union is a wholly owned subsidiary of Westcoast Energy Inc. (rated A (low)), which is indirectly owned by Spectra Energy Corp. This ownership structure limits Union's ability to access the equity markets directly. As a result, additional cash flow needs are largely financed through retained earnings and debt issuances.

Organizational Chart (as at September 30, 2013)



(1) This is an intercompany loan from GLBE.

Earnings and Outlook

(CA$ millions where applicable)	USGAAP 9 mos. Sept. 30 2013	USGAAP 9 mos. Sept. 30 2012	USGAAP 12 mos. Sept. 30 2013	USGAAP For the year ended December 31 2012	USGAAP 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008
Gas distribution margin	553	501	779	727	713	699	658	675
Storage and transportation revenues	193	244	218	269	311	308	299	244
Ancillary revenue	15	17	26	28	34	29	36	34
Operating revenue	761	762	1,023	1,024	1,058	1,036	993	953
Total operating expense	494	486	666	658	646	631	608	587
EBITDA	422	435	566	579	617	605	580	552
EBIT	267	276	357	366	412	405	385	366
Gross interest expense	114	117	153	156	153	159	164	155
Earnings before taxes	153	159	204	210	259	247	223	221
Net income before non-recurring items (1)	127	123	174	170	201	206	175	180
Reported net income	143	123	190	170	201	206	175	180
Return on equity	12.9%	12.8%	12.9%	13.6%	14.9%	14.2%	12.2%	12.8%
Distribution rate base	N/A	N/A	N/A	3,749	3,583	3,570	3,483	3,348

(1) 2013 adjusted for $16 million decrease in taxes due to recognition of tax benefits for 2008 through 2012 tax years.
(2) N/A: Not available on a quarterly basis

2013 Summary

- Union's earnings are principally generated from its regulated gas distribution, storage and transmission businesses. However, earnings from the unregulated storage business have continued to grow, accounting for approximately 20% of EBIT in 2012, up from around 14% in 2008 (based on Union's regulatory filing).
- Earnings before non-recurring items in 9M2013 remained stable compared to 9M2012. The increase in the number of customers, rates and usage and favourable changes in taxes have been offset by higher employee benefit costs, lower short term transportation services, lower prices for storage services, and revenue sharing with customers from the optimization of upstream transportation contracts.

2014 Outlook

- DBRS anticipates that Union's earnings will likely increase modestly in 2014 due to distribution rate increases and customer growth.
- Although weather conditions are unpredictable, DBRS expects ongoing energy conservation programs, including the Company's Demand Side Management Initiative, to have a modest impact on customer usage. This could potentially be offset by modest customer growth.
- Long-term earnings from unregulated storage are expected to increase, reflecting an increase in demand for gas storage in Ontario and Company's intention to expand its storage capacity.

DBRS

Union Gas Limited

Report Date:
February 20, 2014

Financial Profile

	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP
	9 mos. Sept. 30		12 mos. Sept. 30	For the year ended December 31				
(CA$ millions where applicable)	2013	2012	2013	2012	2011	2010	2009	2008
Net income before non-recurring items	127	123	174	170	201	206	175	180
Depreciation & amortization	155	159	209	213	205	200	195	187
Deferred income taxes and other	14	(4)	10	(8)	8	25	(55)	13
Cash flow (bef. working cap. changes)	296	278	393	375	414	431	315	380
Dividends paid	(51)	(34)	(182)	(165)	(147)	(308)	(50)	(120)
Capital expenditures	(246)	(171)	(346)	(271)	(290)	(232)	(247)	(404)
Free cash flow (bef. working cap. changes)	(1)	73	(135)	(61)	(23)	(109)	18	(144)
Changes in non-cash work. cap. items	(35)	72	(49)	58	(55)	(257)	327	(218)
Net Free Cash Flow	(36)	145	(184)	(3)	(78)	(366)	345	(362)
Acquisitions & long-term investments	0	0	0	0	0	0	0	0
Short-term investments	0	0	0	0	0	0	0	0
Proceeds on asset sales	0	0	0	0	0	0	0	0
Net equity change	0	0	0	0	0	0	0	0
Net debt change	39	(144)	188	5	73	344	(311)	362
Other	0	0	0	0	0	0	0	0
Change in cash	3	1	4	2	(5)	(22)	34	0
Total debt	2,709	2,521	2,709	2,670	2,665	2,583	2,240	2,550
Cash and equivalents	12	8	12	9	7	12	34	0
Total debt in capital structure (1)	63.0%	61.8%	63.0%	64.2%	63.4%	64.3%	61.3%	64.2%
Cash flow/Total debt	14.6%	14.7%	14.5%	14.0%	15.5%	16.7%	14.1%	14.9%
EBIT interest coverage (times)	2.34	2.36	2.33	2.35	2.69	2.55	2.35	2.36
Dividend payout ratio	40.2%	27.6%	104.6%	97.1%	73.1%	149.5%	28.6%	66.7%

(1) Adjusted for operating leases and accumulated other comprehensive income.

2013 Summary

- Overall, key credit metrics remain reasonable for the current rating category.
- Union generated free cash flow deficits for the past three years and this is expected to continue in the medium term due to higher capex for storage and gas transmission projects.
- Capex was significantly higher in 9M2013 compared to 9M2012, largely due to increased maintenance and expansion projects.
- The dividends are primarily used to maintain Union's capital structure in line with regulatory-approved levels (64% debt and 36% equity).

2014 Outlook

- DBRS expects Union to generate stable cash flows with higher capex in the medium term.
- DBRS expects the Company to maintain its leverage in line with the OEB approved capital structure by prudently managing debt levels and dividend payouts.

Liquidity and Long-Term Debt Maturities

Credit Facility (CA$ millions)	Maturity Date	Committed	CP	Available
			As at September 30, 2013.	
Five-year syndicated credit facility	2016	400	123	277
Total		400	123	277

- The Company's credit facility is mainly used to backstop its $400 million commercial paper program.
- DBRS views Union's liquidity as sufficient for its working capital funding requirements.
- Union is generally subject to seasonality as a part of its business and, as a result, its short-term debt and its gas inventory typically peak in the first and fourth quarters of every year ($123 million outstanding in commercial paper as at September 30, 2013).
- The facility contains a maximum 75% debt-to-capital covenant and includes a provision requiring the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. As at September 30, 2013, the Company was in compliance with these covenants.

Debt Maturity (CA$ millions)	2014	2015	2016	2017	2018	Thereafter	Total
MTNs and Debentures	150	150	200	125	400	1,515	2,540

As at September 30, 2013.

- The Company's debt maturity is well spread out. $150 million of long-term debt is due in 2014. DBRS expects the refinancing risk to be minimal given Union's good access to debt capital markets. The amounts due from 2015 to 2018 remain modest and are also within the financing capacity of the Company.
- In July 2013, the Company issued $250 million of medium-term unsecured note debentures at 3.79% per annum, due July 10, 2023.
- The Company filed a new $800 million base shelf prospectus expiring November 11, 2014, which provides for the issuance of medium-term note debentures. The new base shelf prospectus replaces the $500 million base shelf prospectus that expired on October 10, 2012. As at September 30, 2013, the Company has $550 million available for issuance under the new base shelf prospectus.
- Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants. Therefore, the Company can have a maximum total debt-to-capitalization of 75% and any incremental debt is subject to an interest coverage test of 2.0x. As at September 30, 2013, the Company was in compliance with all covenants.

Long-Term Debt (CA$ millions)		September 30 2013	December 31 2012
7.90%	1994 Series debentures, due February 24, 2014	**150**	150
11.50%	1990 Series debentures, due August 28, 2015	**150**	150
4.64%	Series 5, due June 30, 2016	**200**	200
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
4.85%	Series 7, due April 25, 2022	**125**	125
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9 due June 21, 2041	**300**	300
3.79%	Series 10 due July 10, 2023	**250**	
		2,540	2,290
Less: unamortized debt discount		**3**	3
		2,537	2,287
Less: current portion		**150**	-
		2,387	2,287

Regulation

Regulatory Overview

Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB. (Refer to "Assessment of Union's Regulatory Environment." on Page 8)

Gas Distribution

- The regulatory environment in Ontario for natural gas distributors is viewed as reasonable.
- Union's distribution rates are set under a multi-year IR framework with rebasing under the COS framework between the IR periods.
- From 2014 to 2018, Union will be regulated under the IR framework. Under this framework, Union will be able to increase rates annually by an inflation factor, which will be offset by a productivity factor of 60%; thus the annual net rate escalator in each year is 40% of inflation.
- Union filed an application with the OEB in October 2013 for new rates effective January 1, 2014. If approved, the impact on a typical residential customer would range from an increase of $2 annually to a decrease of $20 annually depending on location. A decision is expected in the first half of 2014.
- For 2014 to 2018, the Company has an approved ROE for 8.93% and a deemed equity component of 36%.
- The Company will be able to continue to pass through gas commodity, upstream transportation and demand side management costs. It will also be allowed additional pass-through of costs associated with major capital investments and certain fuel variances, an allowance for unexpected cost changes that are outside of management's control, equal sharing of taxes between customers, and an earnings sharing mechanism.
- The earnings sharing mechanism permits Union to fully retain the ROE from regulated operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers and share 90% of any earnings above 10.93% with customers.
- In May 2013, Union filed an application with the OEB for the annual disposition of the 2012 non-commodity deferral account balances. The application included a proposal that revenues derived from the optimization of its upstream transportation contracts in 2012 were to be treated as optimization revenues and included in utility earnings rather than a reduction to gas costs. If the OEB finds this to be treated as a reduction to gas costs, 90% of which are to be credited to customer, this would result in a refund payable of approximately $17 million. A hearing was held in October 2013 and a decision is pending. DBRS does not expect this to have a material impact on Union's ratings.
  - The OEB issued a decision on November 19, 2012, that certain 2011 revenues derived from the optimization of upstream transportation contracts would be refunded to customers as well. Union appealed this decision on the basis of impermissible retroactive ratemaking and a hearing was held in October 2013. A decision is pending.

Gas Storage

- Storage services outside Union's franchise area or new storage services to customers in the franchise area are not regulated by the OEB. This accounts for approximately one-third of storage capacity.
- Storage within Union Gas's service area is regulated under the COS regulation.

Assessment of Union's Regulatory Environment

Criteria	Score	Analysis
(1) Deemed Equity	Excellent Very Good Satisfactory **Below Average** Poor	The OEB allows Union to have a deemed equity of 36%, which is consistent with the other gas distributors in Ontario. However, deemed equity is below peer utilities in Canada and the United States.
(2) Allowed ROE	Excellent Very Good **Satisfactory** Below Average Poor	For 2014 to 2018, the Company has an approved ROE of 8.93%. In addition, the earnings sharing mechanism permits Union to fully retain the ROE from regulated operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers and share 90% of any earnings above 10.93% with customers.
(3) Energy Cost Recovery	Excellent **Very Good** Satisfactory Below Average Poor	The Company is able to fully pass through gas commodity, upstream transportation and demand side management costs on a quarterly basis. It is also allowed additional pass-through of costs associated with major capital investments, certain fuel variances and an allowance for unexpected cost changes that are outside of management's control, equal sharing of taxes between customers and an earnings sharing mechanism.
(4) COS vs. IRM	Excellent Very Good **Satisfactory** Below Average Poor	Union's distribution rates are set under a five year IR framework with rebasing under the COS framework between the IR periods. Under this framework, Union will be able to increase rates annually by an inflation factor, which will be offset by a productivity factor of 60% of inflation; thus the annual net rate escalator in each year is 40% of inflation.
(5) Capital Cost Recovery	Excellent **Very Good** Satisfactory Below Average Poor	Major capital costs are pre-approved by the regulator and added to rate base after the completion. Other capital spending after the base year will not be approved until the next rate application and approval of the rate base.

Criteria	Score	Analysis
(6) Political Interference	Excellent **Very Good** Satisfactory Below Average Poor	There is low degree of government influence. Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB.
(7) Retail Rate	Excellent **Very Good** Satisfactory Below Average Poor	In the natural gas sector, the OEB regulates Ontario's natural gas utilities which are required to submit the rates they propose to charge their customers to the Board for review and approval. The cost of natural gas distributed by Union Gas is set by the OEB at 13.3052 ¢/m3 (January 2014), which is higher than rates charged by Enbridge (11.7412 ¢/m3) but generally lower compared to other provinces in Canada. Rates are dictated by commodity costs and transportation tolls on pipelines. Economic environment in Ontario is considered good.
(8) Stranded Cost Recovery	**Excellent** Very Good Satisfactory Below Average Poor	Union has very limited history of stranded costs.
(9) Rate Freeze	**Excellent** Very Good Satisfactory Below Average Poor	Rates are based on the market price of natural gas plus distribution and servicing costs. Rates have not been frozen within the past decade.
(10) Market Structure (Deregulation)	Excellent Very Good **Satisfactory** Below Average Poor	The natural gas sector is partially deregulated such that a portion of consumers can choose their supplier. Union Gas does not produce or extract natural gas but provides storage and transportation services. There is reasonable regulatory oversight on distribution rates.

Union Gas Limited

Report Date:
February 20, 2014

Union Gas Limited

Balance Sheet (CA$ millions) Assets	USGAAP Sept. 30 2013	USGAAP Dec. 31 2012	USGAAP Dec. 31 2011	Liabilities & Equity	USGAAP Sept. 30 2013	USGAAP Dec. 31 2012	USGAAP Dec. 31 2011
Cash & equivalents	12	9	7	S.T. borrowings	172	383	378
Accounts receivable	542	588	536	Accounts payable	742	685	622
Inventories	293	199	263	Current portion L.T.D.	150	0	0
Deferred income taxes & others	8	14	8	Income taxes payable & others	2	26	26
Total Current Assets	855	810	814	**Total Current Liab.**	1,066	1,094	1,026
Net fixed assets	4,689	4,567	4,495	Long-term debt	2,387	2,287	2,287
Future income tax assets	0	0	0	Asset retirement obligations	149	143	134
Regulatory assets & others	426	406	355	Deferred income taxes	370	352	293
				Regulatory liabilities & others	630	645	686
				Minority interest	9	9	9
				Preferred shares	110	110	110
				Common equity	1,249	1,143	1,119
Total Assets	5,970	5,783	5,664	**Total Liab. & SE**	5,970	5,783	5,664

Balance Sheet & Liquidity & Capital Ratios	USGAAP 9 mos. Sept. 30 2013	USGAAP 9 mos. Sept. 30 2012	USGAAP 12 mos. Sept. 30 2013	USGAAP For the year ended December 31 2012	USGAAP 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008
Current ratio	0.80	0.83	0.80	0.74	0.79	0.59	0.58	0.83
Total debt in capital structure	62.8%	61.5%	62.8%	63.9%	63.9%	64.0%	60.9%	64.1%
Total debt in capital structure (1)	63.0%	61.8%	63.0%	64.2%	63.4%	64.3%	61.3%	64.2%
Cash flow/Total debt	14.6%	14.7%	14.5%	14.0%	15.5%	16.7%	14.1%	14.9%
Cash flow/Total debt (1)	14.4%	14.5%	14.3%	13.9%	15.9%	16.5%	13.8%	14.8%
(Cash flow-dividends)/Capex	1.00	1.43	0.61	0.77	0.92	0.53	1.07	0.64
Dividend payout ratio	40.2%	27.6%	104.6%	97.1%	73.1%	149.5%	28.6%	66.7%
Coverage Ratios (times)								
EBIT gross interest coverage	2.34	2.36	2.33	2.35	2.69	2.55	2.35	2.36
EBITDA gross interest coverage	3.70	3.72	3.70	3.71	4.03	3.81	3.54	3.56
Fixed-charges coverage	2.29	2.31	2.27	2.29	2.64	2.50	2.29	2.27
EBIT gross interest coverage (1)	2.35	2.37	2.34	2.35	2.70	2.55	2.36	2.36
Profitability Ratios								
EBITDA margin	55.5%	57.1%	55.3%	56.5%	58.3%	58.4%	58.4%	57.9%
EBIT margin	35.1%	36.2%	34.9%	35.7%	38.9%	39.1%	38.8%	38.4%
Profit margin	16.7%	16.1%	17.0%	16.6%	19.0%	19.9%	17.6%	18.9%
Return on equity	12.9%	12.8%	12.9%	13.6%	14.9%	14.2%	12.2%	12.8%
Return on capital (1)	6.6%	6.8%	6.8%	6.8%	7.6%	8.1%	7.3%	7.3%

(1) Adjusted for operating leases and accumulated other comprehensive income.

DBRS

Union Gas Limited

Report Date:
February 20, 2014

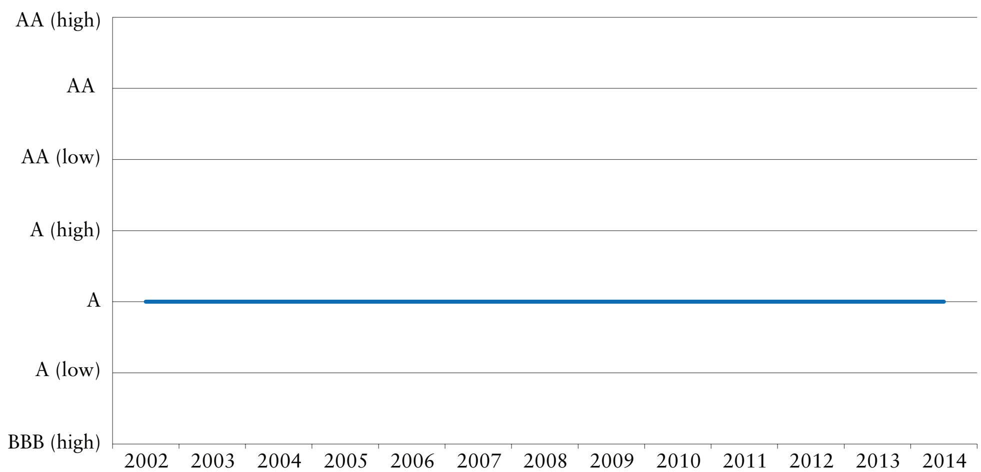
Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures/Medium-Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating History

	Current	2013	2012	2011	2010	2009
Issuer Rating	A	A	A	NR	NR	NR
Unsecured Debentures/ Medium-Term Note Debentures	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cumulative Redeemable Preferred Shares	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Ratings History of Union Gas Limited



Note: All figures are in Canadian dollars unless otherwise noted.

Rating Report

Union Gas Limited

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DBRS

Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures/Medium-Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating Update

DBRS Limited (DBRS) has confirmed the ratings of Union Gas Limited (Union or the Company) as listed above. The ratings reflect Union's relatively low risk gas distribution business, which operates under a reasonable regulatory framework, and are supported by the Company's economically stable service territory with a large customer base that is growing at a steady rate. Union's financial risk profile has remained reasonable with key credit metrics in the current rating category.

Union's business risk profile is supported by a reasonable regulatory environment in Ontario and predictable earnings from the Company's regulated business, which accounts for over 80% of earnings. Union operates under a five-year incentive regulation framework (IR; 2014–2018), which provides predictable cash flows and annual rate escalation at 40% of inflation. The IR also affords the Company an opportunity to earn 150 basis points above the allowed return on equity (ROE) of 8.93% through its operational efficiency and an earnings sharing mechanism with its customers. Natural gas supply costs continue to be passed through to customers, which mitigates commodity price risk for Union. DBRS believes the IR framework is well suited to Union's large multi-year capital programs that require certainty of funding in advance as capex is pre-approved by the Ontario Energy Board (OEB), reducing regulatory lag. The Company's distribution business serves 1.4 million customers, largely in residential and commercial markets in more than 400 communities across Ontario, and provides Union the ability to better weather economic downturns. Although the Company's regulated distribution and storage business accounts for the bulk of the Company's earnings, a portion of earnings are generated from its unregulated storage business (14% of EBIT in 2013), which could expose the Company to some earnings volatility. DBRS views this segment as higher risk than the regulated distribution and storage business because of the impact of seasonality on storage demand and rates.

DBRS expects capex, largely related to Dawn to Parkway transmission and storage expansions, to remain relatively high (approximately $400 million annually in 2015 and 2016), resulting in the Company's generating negative free cash flows over the medium term. The new infrastructure is needed to offset the declining supplies from Western Canada and support diverse and competitive gas supply options from Marcellus and Utica. Union's credit metrics could come under pressure as major capital projects are executed; however, the impact is expected to be moderate, as the assets are placed into service and form part of the Company's regulatory rate base, enhancing earnings. In addition, DBRS expects the Company to maintain a fairly flexible dividend policy, which helps to maintain its regulated capital structure (64% debt/36% equity).

Financial Information

	9 mos. Sept. 30		12 mos. Sept. 30	For the year ended December 31				
(CA$ millions where applicable)	**2014**	**2013**	**2014**	**2013**	**2012**	**2011**	**2010**	**2009**
EBIT gross interest coverage (times)	2.50	2.34	2.59	2.48	2.35	2.69	2.55	2.35
Total debt in capital structure 1	63.7%	63.0%	63.7%	65.1%	64.2%	63.4%	64.3%	61.3%
Cash flow/Total debt	13.6%	14.6%	14.2%	14.4%	14.0%	15.5%	16.7%	14.1%
Net income before non-recurring items	146	127	210	191	170	201	206	175
Cash flow from operations	303	296	421	414	375	414	431	315

1 Adjusted for operating leases and accumulated other comprehensive income.

Issuer Description

Union Gas Limited is a utility that provides natural gas distribution, transmission and storage services in southwestern, northern and eastern Ontario, serving approximately 1.4 million customers. Union Gas' common stock is held by Great Lakes Basin Energy L.P. (GLBE), a wholly owned limited partnership of Westcoast Energy Inc. (rated A (low)). Westcoast is indirectly owned by Spectra Energy Capital, LLC (rated BBB).

Rating Considerations

Strengths

1. Reasonable regulatory environment

Union's gas regulated distribution business operates under a reasonably stable regulatory environment, which provides predictable cash flows and allows the Company to earn a reasonable return on its investments as major capex is pre-approved. The Company currently operates under a five-year IR framework (2014 to 2018), with rebasing under the cost-of-service (COS) framework in between. Union's regulated distribution business is not exposed to commodity price risk, as gas supply costs are adjusted quarterly and passed through to customers.

2. Large customer base and strong franchise

Union's cash flow is supported by a large customer base (1.4 million), which is growing at a steady rate of approximately 2%, making it one of the largest natural gas distributors in Canada. Union provides transportation and storage services to almost all—and distribution to most—gas-fired generation plants in Ontario. The Company's Dawn storage facility (156 billion cubic feet of capacity) acts as a gateway for Marcellus/Utica gas and is strategically connected to key pipelines transporting natural gas to major Canadian and U.S. markets. Long-term demand for natural gas in Ontario is expected to remain relatively stable with continued growth in peak day demands. Moreover, the Company's franchise area covers more than 400 communities in northern, southwestern and eastern Ontario. Approximately 50% of Union's revenue is generated from residential customers, a segment that is less exposed to economic downturns.

3. Reasonable credit metrics

For the 12 months ended September 30, 2014, Union's debt-to-capital ratio (63.7%), EBIT interest coverage (2.5 times (x)) and cash flow-to-debt (13.6%) remained reasonable for its rating category. Union is committed to maintaining its capital structure for the regulated operations in line with the regulatory capital structure of 64% debt and 36% equity.

Challenges

1. Consistent free cash flow deficits

Union has generated free cash flow deficits for the past five years, and this is expected to continue in the medium term due to higher capex for storage and transmission projects. DBRS expects the Company to finance the deficits by managing dividends and issuing new debt in a prudent manner and maintain its debt-to-capital ratio within regulatory levels.

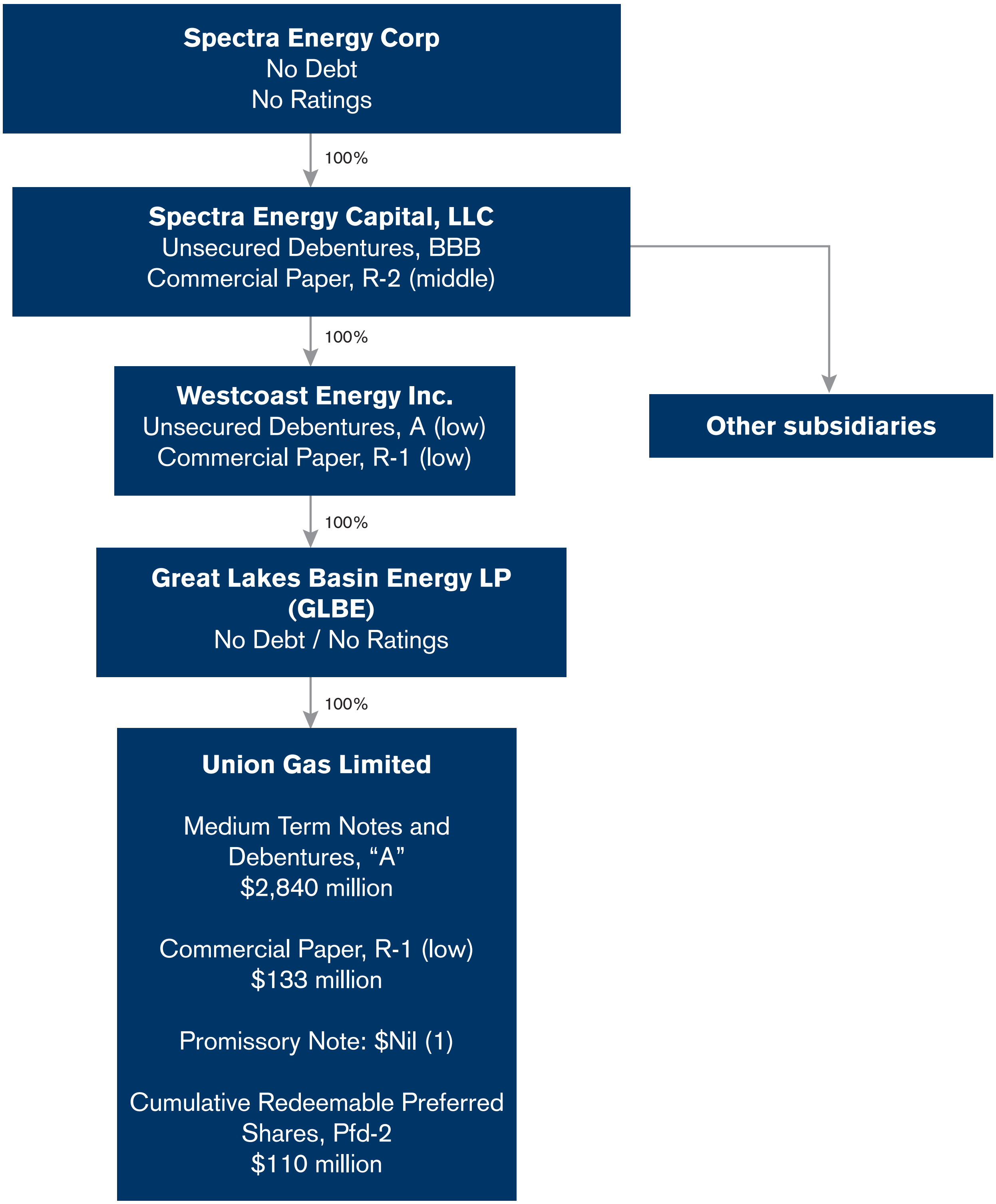
2. Seasonality and Volume risk

Union is exposed to a degree of demand risk, since its rates are based on forecast volumes, which are sensitive to changes in weather. Natural gas rates approved by the OEB assume normal weather conditions. Since a majority of the gas distributed by Union to the residential and commercial markets is used for space heating and is charged using volume-based rates, differences from normal weather could have a significant effect on the consumption of gas and on the Company's financial results. However, DBRS notes that under the IR framework, Union is allowed to recover shortfalls relative to normalized consumption on an annual basis with a one-year lag, and has also increased fixed monthly charges for residential and small commercial customers to partially mitigate the impact of volume changes.

3. Earnings volatility of non-regulated storage

Union's non-regulated storage earnings may result in earnings volatility. DBRS views this segment as higher risk than the regulated distribution and storage business because of the impact of seasonality on storage demand and rates. In 2013, Union's non-regulated storage business accounted for approximately 14% of EBIT (20% in 2012).

Organizational Chart (as at September 30, 2014)



(1) The Company also has a promissory note to borrow up to $150 million from GLBE on an unsecured basis.

Earnings and Outlook

	9 mos. Sept. 30		12 mos. Sept. 30	For the year ended December 31				
(CA$ millions where applicable)	**2014**	**2013**	**2014**	**2013**	**2012**	**2011**	**2010**	**2009**
Gas distribution margin	570	553	789	772	727	713	699	658
Storage and transportation revenues	209	193	268	252	269	311	308	299
Ancillary revenue	8	15	19	26	28	34	29	36
Operating revenue	787	761	1,076	1,050	1,024	1,058	1,036	993
Total operating expense	495	494	669	668	658	646	631	608
EBITDA	451	422	615	586	579	617	605	580
EBIT	292	267	407	382	366	412	405	385
Gross interest expense	117	114	157	154	156	153	159	164
Earning before taxes	175	153	250	228	210	259	247	223
Net income before non-recurring items 1	146	127	210	191	170	201	206	175
Reported net income	145	143	209	207	170	201	206	175
Return on equity	13.1%	12.9%	14.3%	14.3%	13.6%	14.9%	14.2%	12.2%
Distribution rate base	n/a	n/a	n/a	3,784	3,749	3,583	3,570	3,483

1 2013 adjusted for $16 million decrease in taxes due to recognition of tax benefits for 2008 through 2012 tax years. 2 n/a: not available on a quarterly basis

2014 Summary

- Union's earnings are principally generated from its regulated gas distribution, storage and transmission businesses. However, earnings from the unregulated storage business, which carries some earnings volatility resulting from fluctuating demand and rates, contributed approximately 14% of 2013 EBIT (20% in 2012).
- The natural gas distribution business is subject to seasonality related to volume-based rates and the significant effect of the winter heating season on volumes.
- EBIT increased for 9M2014 compared with 9M2013 primarily resulting from higher customer usage of natural gas because of colder weather, in addition to customer growth.

2015 Outlook

- DBRS anticipates that Union's earnings will likely increase modestly in 2015 as a result of distribution rate increases and customer growth.
- Although weather conditions are unpredictable, DBRS expects ongoing energy conservation programs, including the Company's Demand Side Management Initiative, to have a modest impact on customer usage. This will likely be offset by modest annual customer growth of approximately 2%.

Financial Profile

	9 mos. Sept. 30		12 mos. Sept. 30	For the year ended December 31				
(CA$ millions where applicable)	2014	2013	2014	2013	2012	2011	2010	2009
Net income before non-recurring items	146	127	210	191	170	201	206	175
Depreciation & amortization	159	155	208	204	213	205	200	195
Deferred income taxes and other	(2)	14	3	19	(8)	8	25	(55)
Cash flow (bef. working cap. changes)	303	296	421	414	375	414	431	315
Dividends paid	(2)	(51)	(103)	(152)	(165)	(147)	(308)	(50)
Capital expenditures	(285)	(246)	(409)	(370)	(271)	(290)	(232)	(247)
Free cash flow (bef. working cap. changes)	16	(1)	(91)	(108)	(61)	(23)	(109)	18
Changes in non-cash work. cap. items	(105)	(35)	(164)	(94)	58	(55)	(257)	327
Net Free Cash Flow	(89)	(36)	(255)	(202)	(3)	(78)	(366)	345
Acquisitions & long-term investments	0	0	0	0	0	0	0	0
Short-term investments	0	0	0	0	0	0	0	0
Proceeds on asset sales	0	0	0	0	0	0	0	0
Net equity change	0	0	0	0	0	0	0	0
Net debt change	97	39	261	203	5	73	344	(311)
Other	0	0	0	0	0	0	0	0
Change in cash	8	3	6	1	2	(5)	(22)	34
Total debt	**2,970**	**2,709**	**2,970**	**2,873**	**2,670**	**2,665**	**2,583**	**2,240**
Cash and equivalents	18	12	18	10	9	7	12	34
Total debt in capital structure 1	63.7%	63.0%	63.7%	65.1%	64.2%	63.4%	64.3%	61.3%
Cash flow/Total debt	13.6%	14.6%	14.2%	14.4%	14.0%	15.5%	16.7%	14.1%
EBIT interest coverage (times)	2.50	2.34	2.59	2.48	2.35	2.69	2.55	2.35
Dividend payout ratio	1.4%	40.2%	49.1%	79.6%	97.1%	73.1%	149.5%	28.6%

1 Adjusted for operating leases and accumulated other comprehensive income.

2014 Summary

- Overall, key credit metrics remain reasonable for the current rating category.
- Operating cash flow remains predictable and has improved over time in line with an increasing rate base.
- Capex has been relatively high because of the construction of compressors and related facilities at the Parkway compressor station. These projects were pre-approved by the OEB in January 2014 for rate recovery and will be in service in the fall of 2015.
- Dividends are primarily used to maintain Union's capital structure in line with regulatory-approved levels (64% debt and 36% equity); as a result, dividends paid are low at $2 million for 9M2014. Starting in 2014, Union plans to pay dividends annually instead of quarterly.
- Union has generated free cash flow deficits for the past five years, and this is expected to continue in the medium term because of higher capex for storage and transmission projects. Free cash flow deficits are debt financed.
- Changes in non-cash working capital was higher for 9M2014 because of the seasonality of the business, and Q3 inventory injections exceeded withdrawals, resulting in increased short-term borrowings.
- Q4 2014 earnings were in line with expectations and marginally affected by lower customer usage related to the warmer weather.

2015 Outlook

- Capex for 2015 is expected to be approximately $450 million, largely associated with Dawn to Parkway expansions. Financing of the capex program is not expected to have a material impact on the Company's financial profile. DBRS expects the Company to maintain its leverage in line with the OEB-approved capital structure by prudently managing debt levels and dividend payouts.
- In September 2014, Union applied for OEB approval for construction of the Dawn to Parkway 2016 Expansion Project. This project involves the installation of a new compressor, modifications to existing facilities and construction of natural gas pipelines. These facilities will provide incremental capacity on the transmission system and are supported by contracts with Union's storage and transmission customers. The total capital cost is expected to be $416 million with an in-service date of Q4 2016.

Liquidity and Long-Term Debt Maturities

Credit Facility as at September 30, 2014

(CA$ millions)	Maturity Date	Committed	CP	Available
Five-year syndicated credit facility	2016	400	133	267

- The Company's credit facility is mainly used to backstop its $400 million commercial paper program, which supports Company's working capital needs.
- DBRS views Union's liquidity as sufficient for its working capital funding requirements.
- Union is generally subject to seasonality as a part of its business, and as a result, its short-term debt and its gas inventory typically peak in the first and fourth quarters of every year.
- The facility contains a maximum 75% debt-to-capital covenant and includes a provision requiring the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. As at September 30, 2014, the Company was in compliance with these covenants.

Debt Maturity as at September 30, 2014

(CA$ millions)	2015	2016	2017	2018	Thereafter	Total
MTNs and Debentures	150	200	125	400	1,965	2,840

- The Company's debt maturity is well spread out, and $150 million of long-term debt is due in 2015. DBRS expects the refinancing risk to be minimal, given Union's good access to debt capital markets. The amounts due from 2016 to 2018 remain modest and are also within the financing capacity of the Company.
- In June 2014, the Company issued 2.76% $200 million of medium-term unsecured note debentures due June 2021 and 4.20% $250 million medium-term note debentures due June 2044.
- The Company filed a new $1.5 billion base shelf prospectus expiring January 3, 2017, which provides for the issuance of medium-term note debentures. The new base shelf prospectus replaces the $800 million base shelf prospectus that expired November 11, 2014.
- Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants. Therefore, the Company can have a maximum total debt-to-capitalization of 75%, and any incremental debt is subject to a minimum interest coverage test of 2.0x. As at September 30, 2014, the Company was in compliance with all covenants.

Long-Term Debt

		September 30	
(CA$ millions)		2014	2013
7.90%	1994 Series debentures, due February 24, 2014	-	150
11.50%	1990 Series debentures, due August 28, 2015	150	150
4.64%	Series 5, due June 30, 2016	200	200
9.70%	1992 Series II debentures, due November 6, 2017	125	125
5.35%	Series 6, due April 27, 2018	200	200
8.75%	1993 Series debentures, due August 3, 2018	125	125
8.65%	Senior debentures, due October 19, 2018	75	75
4.85%	Series 7, due April 25, 2022	125	125
8.65%	1995 Series debentures, due November 10, 2025	125	125
5.46%	Series 6, due September 11, 2036	165	165
6.05%	Series 7, due September 2, 2038	300	300
5.20%	Series 8, due July 23, 2040	250	250
4.88%	Series 9 due June 21, 2041	300	300
3.79%	Series 10 due July 10, 2023	250	250
2.76%	Series 11 due June 2021	200	-
4.20%	Series 12 due June 2044	250	-
		2,840	2,540
Less: unamortized debt discount		3	3
		2,837	2,537
Less: current portion		150	150
		2,687	**2,387**

Regulation

Regulatory Overview

Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB. (Refer to "Assessment of Union's Regulatory Environment" on page 8). The regulatory environment in Ontario for natural gas distributors is viewed as reasonable.

Gas Distribution

- Union's distribution rates are set under a multi-year IR framework with rebasing under the COS framework between the IR periods.
- From 2014 to 2018, Union will be regulated under the IR framework. Under this framework, Union will be able to increase rates annually by an inflation factor, which will be offset by a productivity factor of 60%; thus, the annual net rate escalator in each year is 40% of inflation.
- For 2014 to 2018, the Company has an approved ROE for 8.93% and a deemed equity component of 36%. The earnings sharing mechanism permits Union to fully retain the ROE from regulated operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.
- The Company is allowed to pass through gas commodity, upstream transportation and demand side management costs to customers. It will also be allowed additional pass-through of costs associated with major capital investments and certain fuel variances, an allowance for unexpected cost changes that are outside of management's control, equal sharing of taxes between customers and an earnings sharing mechanism.
- In September 2014, Union filed an application with the OEB for new rates effective January 1, 2015. The impact of the new rates on a typical residential customer would range from an increase of $1 to $4 annually, depending on the location within its service territory. The OEB approved the new rates on December 19, 2014.

Gas Storage

- Storage services outside Union's franchise area or new storage services to customers in the franchise area are not regulated by the OEB. This accounts for approximately one-third of storage capacity.
- Storage within Union Gas's service area is regulated under the COS regulation.

Upstream Regulation – LDCs settlement

- In September 2013, Eastern Canadian LDCs Union Gas, Gaz Métro Limited Partnership and Enbridge Gas Distribution Inc. reached a settlement agreement with TransCanada that provides market access to supplies at Dawn and Niagara, provides long-term market and toll certainty, eliminates all regulatory and legal challenges and allows TransCanada a reasonable opportunity to recover its costs.
- In December 2013, TransCanada filed an application with the National Energy Board (NEB) for approval of tolls and services for 2015 through 2020, as provided for in the settlement agreement. The NEB approved the application in November 2014.

Assessment of Union's Regulatory Environment

Criteria	Score	Analysis
Deemed Equity	Excellent Good Satisfactory **Below Average** Poor	The OEB allows Union to have a deemed equity of 36%, which is consistent with the other gas distributors in Ontario. However, deemed equity is below peer utilities in Canada and the United States.
Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	For 2014 to 2018, the Company has an approved ROE of 8.93%. In addition, the earnings sharing mechanism permits Union to fully retain the ROE from regulated operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.
Energy Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	The Company is able to fully pass through gas commodity, upstream transportation and demand side management costs on a quarterly basis. It is also allowed additional pass-through of costs associated with major capital investments and certain fuel variances, an allowance for unexpected cost changes that are outside of management's control, equal sharing of taxes between customers and an earnings sharing mechanism.
COS vs. IRM	Excellent Good **Satisfactory** Below Average Poor	Union's distribution rates are set under a five-year IR framework with rebasing under the COS framework between the IR periods. Under this framework, Union will be able to increase rates annually by an inflation factor, which will be offset by a productivity factor of 60% of inflation; thus, the annual net rate escalator in each year is 40% of inflation.
Capital Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Major capital costs are pre-approved by the regulator and added to rate base after the completion. Other capital spending after the base year will not be approved until the next rate application and approval of the rate base.
Political Interference	Excellent **Good** Satisfactory Below Average Poor	There is low degree of government influence. Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB.
Retail Rate	Excellent **Good** Satisfactory Below Average Poor	In the natural gas sector, the OEB regulates Ontario's natural gas utilities, which are required to submit the rates they propose to charge their customers to the Board for review and approval. The cost of natural gas distributed by Union Gas is set by the OEB at 18.9887 ¢/m3 (January 2015), which is higher than rates charged by Enbridge (18.3160 ¢/m3) but generally lower compared with other provinces in Canada. Rates are dictated by commodity costs and transportation tolls on pipelines. Economic environment in Ontario is considered good.
Stranded Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	Union has very limited history of stranded costs.
Rate Freeze	**Excellent** Good Satisfactory Below Average Poor	Rates are based on the market price of natural gas plus distribution and servicing costs. Rates have not been frozen within the past decade.
Market Structure (Deregulation)	Excellent Good **Satisfactory** Below Average Poor	The natural gas sector is partially deregulated such that a portion of consumers can chose their supplier. Union Gas does not produce or extract natural gas but provides storage and transportation services. There is reasonable regulatory oversight on distribution rates.

Union Gas Limited

Balance Sheet

(CA$ millions)	Sept. 30	Dec. 31			Sept. 30	Dec. 31	
Assets	**2014**	**2013**	**2012**	**Liabilities & Equity**	**2014**	**2013**	**2012**
Cash & equivalents	18	10	9	S.T. borrowings	133	336	383
Accounts receivable	970	867	588	Accounts payable	1,044	874	685
Inventories	346	160	199	Current portion L.T.D.	150	150	0
Deferred income taxes & other	0	8	14	Deferred taxes & other	12	0	26
Total Current Assets	**1,334**	**1,045**	**810**	**Total Current Liab.**	**1,339**	**1,360**	**1,094**
Net fixed assets	4,989	4,847	4,567	Long-term debt	2,687	2,387	2,287
Future income tax assets	0	0	0	Asset retirement obligations	340	328	143
Regulatory assets & others	522	483	406	Deferred income taxes	428	408	352
				Regulatory liabilities & others	490	484	645
				Minority interest	8	9	9
				Preferred shares	110	110	110
				Common equity	1,443	1,289	1,143
Total Assets	**6,845**	**6,375**	**5,783**	**Total Liab. & SE**	**6,845**	**6,375**	**5,783**

Balance Sheet & Liquidity & Capital Ratios

	9 mos. Sept. 30		12 mos. Sept. 30	For the year ended December 31				
	2014	**2013**	**2014**	**2013**	**2012**	**2011**	**2010**	**2009**
Current ratio	1.00	0.80	1.00	0.77	0.74	0.79	0.59	0.58
Total debt in capital structure	63.4%	62.8%	63.4%	64.7%	63.9%	63.9%	64.0%	60.9%
Total debt in capital structure 1	63.7%	63.0%	63.7%	65.1%	64.2%	63.4%	64.3%	61.3%
Cash flow/Total debt	13.6%	14.6%	14.2%	14.4%	14.0%	15.5%	16.7%	14.1%
Cash flow/Total debt 1	13.4%	14.4%	14.0%	14.2%	13.9%	15.9%	16.5%	13.8%
(Cash flow-dividends)/Capex	1.06	1.00	0.78	0.71	0.77	0.92	0.53	1.07
Dividend payout ratio	1.4%	40.2%	49.1%	79.6%	97.1%	73.1%	149.5%	28.6%
Coverage Ratios (times)								
EBIT gross interest coverage	2.50	2.34	2.59	2.48	2.35	2.69	2.55	2.35
EBITDA gross interest coverage	3.85	3.70	3.92	3.81	3.71	4.03	3.81	3.54
Fixed-charges coverage	2.44	2.29	2.53	2.42	2.29	2.64	2.50	2.29
EBIT gross interest coverage 1	2.50	2.35	2.60	2.49	2.35	2.70	2.55	2.36
Profitability Ratios								
EBITDA margin	57.3%	55.5%	57.2%	55.8%	56.5%	58.3%	58.4%	58.4%
EBIT margin	37.1%	35.1%	37.8%	36.4%	35.7%	38.9%	39.1%	38.8%
Profit margin	18.5%	16.7%	19.5%	18.2%	16.6%	19.0%	19.9%	17.6%
Return on equity	13.1%	12.9%	14.3%	14.3%	13.6%	14.9%	14.2%	12.2%
Return on capital 1	6.7%	6.6%	7.2%	7.0%	6.8%	7.6%	8.1%	7.3%

1 Adjusted for operating leases and accumulated other comprehensive income.

Rating History

	Current	2014	2013	2012	2011	2010-09
Issuer Rating	A	A	A	A	NR	NR
Unsecured Debentures/ Medium-Term Note Debentures	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cumulative Redeemable Preferred Shares	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Commercial Paper Limit

- $400 million

Previous Report

- Union Gas Limited, Rating Report, Februay 20, 2014.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Rating Report

Union Gas Limited

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DBRS

Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures/Medium-Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating Update

On February 9, 2016, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debentures/Medium-Term Note Debentures rating of Union Gas Limited (Union or the Company) at "A," the Company's Commercial Paper rating at R-1 (low) and its Cumulative Redeemable Preferred Shares rating at Pfd-2. All trends are Stable. The ratings confirmation reflects Union's relatively low risk gas distribution business, which operates under a reasonable regulatory framework in an economically stable service territory with a large customer base that is growing at a steady rate. The Company's financial risk profile also remains reasonable with key credits metrics that are supportive of the current ratings.

Union's business risk profile is supported by a reasonable regulatory environment in Ontario and predictable earnings from the Company's regulated business, which account for nearly 90% of earnings (approximately 88% of EBIT in 2014). Union operates under a five-year incentive regulation framework (IR; 2014–2018), which provides predictable cash flows and annual rate escalation at 40% of inflation. The IR also affords the Company an opportunity to earn up to 150 basis points above the allowed return on equity (ROE) of 8.93% through operational efficiency after adjusting for an earnings sharing mechanism with its customers. Natural gas supply costs are passed through to customers, mitigating commodity price risk for Union. The Company's distribution business serves 1.4 million customers, largely in residential and commercial markets in more than 400 communities across Ontario, and provides Union the ability to better weather economic downturns. Although the Company's regulated distribution and storage business accounts for the bulk of the Company's earnings, earnings generated from its unregulated storage business (12% of EBIT in 2014) could expose the Company to some earnings volatility. DBRS views this segment as higher risk than the regulated distribution and storage business because of the impact of seasonality on storage demand and rates.

Union's capital spending program on transmission and storage expansions is expected to remain relatively high (approximately $750 million in 2015 and $1.0 billion in 2016), resulting in the Company's generating negative free cash flows over the medium term. DBRS expects Union's credit metrics to come under pressure, with cash flow-to-debt and debt to capital ratios moving into the "BBB" category, as major capital projects are executed; however, the impact is expected to be mitigated by incremental earnings as projects are completed and placed into service, forming part of the Company's regulatory rate base. In addition to supply diversity, these new infrastructure projects are needed to bring competitively priced Marcellus/Utica natural gas supplies to Eastern Canada.

Continued on P.2

Financial Information

	9 mos. Ending Sep. 30		12 mos. Ending Sep 30	12 mos. Ending Dec. 31			
($ millions where applicable)	**2015**	**2014**	**2015**	**2014**	**2013**	**2012**	**2011**
EBIT interest coverage	2.36	2.48	2.39	2.47	2.48	2.35	2.69
Lease-adjusted debt / capital	63.8%	63.7%	63.8%	65.5%	65.1%	64.2%	63.4%
Cash flow / debt	12.0%	13.6%	12.7%	13.3%	14.4%	14.0%	15.5%
Core net income 1	140	144	190	194	191	170	201
Cash flow from operations	281	303	399	421	414	375	414

1 Net income before non-recurring items.

Issuer Description

Union Gas Limited is a utility that provides natural gas distribution, transmission and storage services in Southwestern, Northern and Eastern Ontario, serving approximately 1.4 million customers. Union Gas' common stock is held by Great Lakes Basin Energy L.P., a wholly owned limited partnership of Westcoast Energy Inc. (rated A (low)). Westcoast is indirectly owned by Spectra Energy Capital, LLC (rated BBB).

Rating Update

DBRS also expects the Company to maintain a flexible dividend policy in order to maintain its regulatory capital structure (64% debt/36% equity). While DBRS does not expect Union's ratings to be upgraded in the medium term, ratings could be negatively affected should leverage exceed the regulatory capital structure and remain elevated for a sustained period.

Rating Considerations

Strengths

1. Reasonable regulatory environment

Union's gas regulated distribution business operates under a reasonable regulatory environment, which provides predictable cash flows and allows the Company to earn a reasonable return on its investments. The Company currently operates under a five-year IR framework (2014 to 2018), with rebasing under the cost-of-service (COS) framework in between. Union's regulated distribution business is not exposed to commodity price risk, as gas supply costs are adjusted quarterly and passed through to customers.

2. Large customer base and strong franchise

Union's cash flow is supported by a large customer base (1.4 million), which is growing at a steady rate, making it one of the largest natural gas distributors in Canada. Union provides transportation and storage services to almost all, and distribution to most, gas-fired generation plants in Ontario. The Company's Dawn storage facility (157 billion cubic feet of capacity) acts as a gateway for Marcellus/Utica gas and is strategically connected to key pipelines transporting natural gas to major Canadian and U.S. markets. Long-term demand for natural gas in Ontario is expected to remain relatively stable with continued growth in peak day demands. Moreover, the Company's franchise area covers more than 400 communities in Northern, Southwestern and Eastern Ontario. Approximately 50% of Union's revenue is generated from residential customers, a segment that is less exposed to economic downturns.

3. Reasonable credit metrics

For the 12 months ended September 30, 2015, Union's lease-adjusted debt-to-capital ratio (63.8%), EBIT interest coverage (2.39 times (x)) and cash flow-to-debt (13.6%) remained reasonable for its rating category. Union is committed to maintaining its capital structure for the regulated operations in line with the regulatory capital structure of 64% debt and 36% equity.

Challenges

1. Consistent free cash flow deficits

Union has generated free cash flow deficits for the past five years, and this is expected to continue in the medium term because of higher capex for storage and transmission projects. DBRS expects the Company to finance the deficits by managing dividends and issuing new debt in a prudent manner, and to maintain its debt-to-capital ratio within regulatory levels.

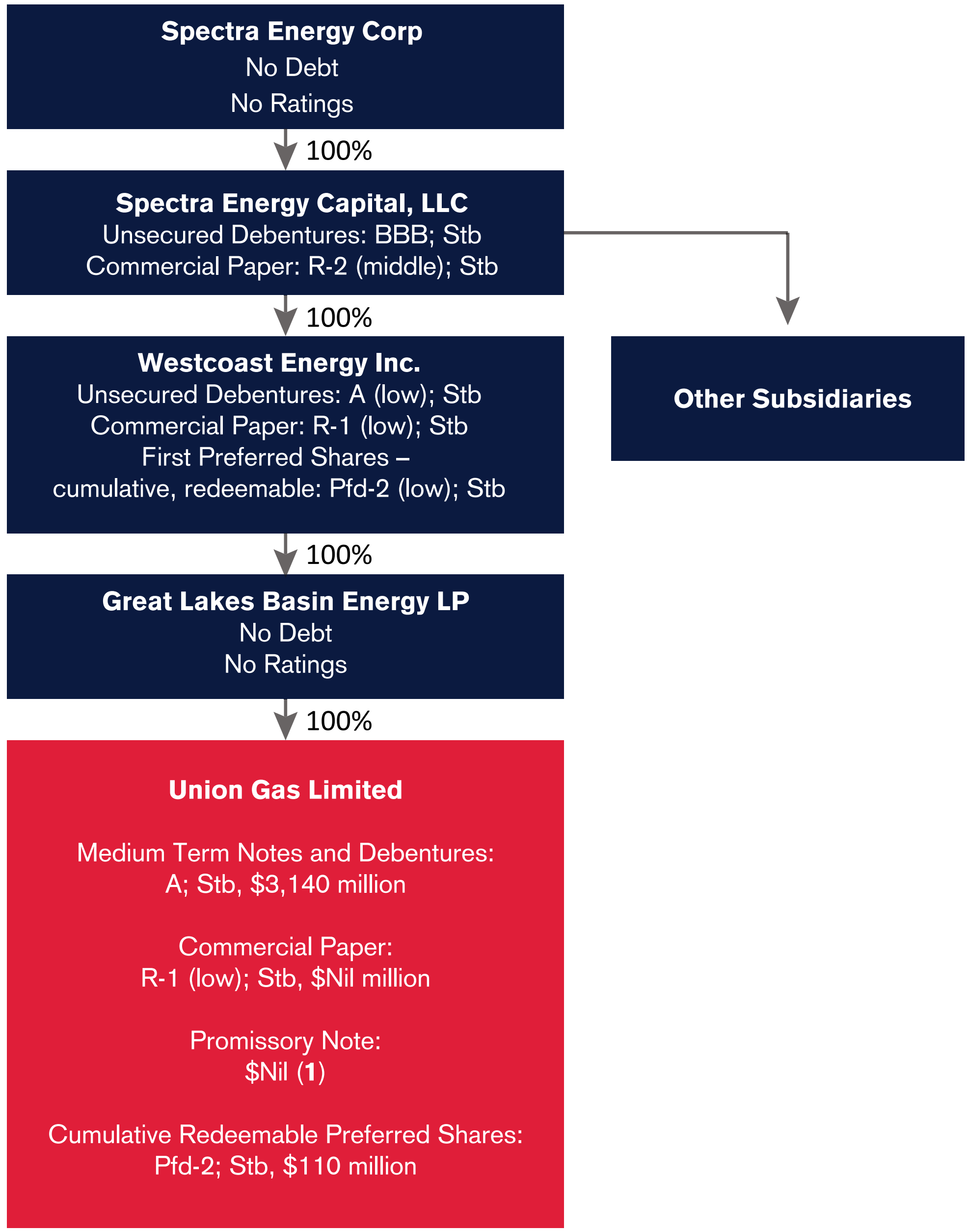
2. Seasonality and volume risk

Union is exposed to a degree of demand risk, since its rates are based on forecast volumes, which are sensitive to changes in weather. Natural gas rates approved by the Ontario Energy Board (OEB) assume normal weather conditions. Since a majority of the gas distributed by Union to the residential and commercial markets is used for space heating and is charged using volume-based rates, differences from normal weather could have a significant effect on the consumption of gas and on the Company's financial results. However, DBRS notes that under the IR framework, Union is allowed to recover shortfalls relative to normalized consumption on an annual basis with a one-year lag. The Company has also increased fixed monthly charges for residential and small commercial customers to partially mitigate the impact of volume changes.

3. Earnings volatility of non-regulated storage

Union's non-regulated storage earnings may result in earnings volatility. DBRS views this segment as higher risk than the regulated distribution and storage business because of the impact of seasonality on storage demand and rates. In 2014, Union's non-regulated storage business accounted for approximately 12% of EBIT (14% in 2013).

Organizational Chart (as at September 30, 2015)



1 The Company has a promissory note to borrow up to $150 million from Great Lakes Basin Energy L.P. on an unsecured basis.

Earnings and Outlook

	9 mos. Ending Sep. 30		12 mos. Ending Sep 30	12 mos. Ending Dec. 31			
($ millions where applicable)	2015	2014	2015	2014	2013	2012	2011
Gas distribution margin	584	570	786	778	772	727	713
Storage and transportation revenues	179	209	222	266	252	269	311
Ancillary revenue	15	8	33	21	26	28	34
Operating revenue	**778**	**787**	**1,041**	**1,065**	**1,050**	**1,024**	**1,058**
Total operating expense	499	497	681	679	668	658	646
EBITDA	**446**	**449**	**595**	**598**	**586**	**579**	**617**
EBIT	**279**	**290**	**375**	**386**	**382**	**366**	**412**
Gross interest expense	118	117	157	156	154	156	153
Earning before taxes	161	173	218	230	228	210	259
Core net income 1, 2	**140**	**144**	**190**	**194**	**191**	**170**	**201**
Reported net income	**140**	**145**	**190**	**195**	**207**	**170**	**201**
Return on common equity	12.5%	13.9%	12.7%	14.5%	15.5%	14.8%	15.9%
Distribution rate base 3	n/a	n/a	n/a	3,976	3,784	3,749	3,583

1 2013 adjusted for $16 million decrease in taxes due to recognition of tax benefits for 2008 through 2012 tax years. 2 Net income before non-recurring items.
3 n/a: not available on a quarterly basis.

2015 Summary

- Nearly 90% of Union's earnings are generated from its regulated gas distribution, storage and transmission businesses. The balance is generated from unregulated storage business, which carries some earnings volatility resulting from fluctuating demand and rates.
- The natural gas distribution business is subject to seasonality related to volume-based rates and the significant effect of the winter heating season on volumes.
- EBIT was marginally lower in the first nine months of 2015 (9M 2015), as a result of the slight increase in the Gas distribution margin resulting from increases in the number of customers and higher increased industrial usage, which were largely offset by decreased residential customer usage caused by warmer weather and lower storage and transportation revenues.

2016 Outlook

- DBRS anticipates that Union's earnings will likely increase modestly in 2016 as a result of rate base growth, distribution rate increases and customer growth.
- Although weather conditions are unpredictable, DBRS expects ongoing energy conservation programs, including the Company's Demand Side Management Initiative, to have a modest impact on customer usage. This will likely be offset by modest annual customer growth of approximately 1% to 2%.

Financial Profile

	9 mos. Ending Sep. 30		12 mos. Ending Sep 30	12 mos. Ending Dec. 31			
($ millions where applicable)	**2015**	**2014**	**2015**	**2014**	**2013**	**2012**	**2011**
Core net income	140	144	190	194	191	170	201
Depreciation & amortization	167	159	220	212	204	213	205
Deferred income taxes and other	(26)	(1)	(11)	14	19	(8)	8
Cash flow (bef. working cap. changes)	**281**	**303**	**399**	**421**	**414**	**375**	**414**
Dividends paid	(2)	(2)	(103)	(103)	(152)	(165)	(147)
Capital expenditures	(474)	(285)	(663)	(474)	(370)	(271)	(290)
Free cash flow (bef. working cap. changes)	**(195)**	**16**	**(367)**	**(156)**	**(108)**	**(61)**	**(23)**
Changes in non-cash work. cap. items	232	(105)	221	(116)	(94)	58	(55)
Net Free Cash Flow	**37**	**(89)**	**(146)**	**(272)**	**(202)**	**(3)**	**(78)**
Acquisitions & long-term investments	0	0	0	0	0	0	0
Short-term investments	0	0	0	0	0	0	0
Proceeds on asset sales	0	0	0	0	0	0	0
Net equity change	(2)	0	(2)	0	0	0	0
Net debt change	(22)	97	163	282	203	5	73
Other	0	0	0	0	0	0	0
Change in cash	**13**	**8**	**15**	**10**	**1**	**2**	**(5)**
Total debt	3,133	2,970	3,133	3,155	2,873	2,670	2,665
Cash and equivalents	33	18	33	20	10	9	7
Lease-adjusted debt / capital	63.8%	63.7%	63.8%	65.5%	65.1%	64.2%	63.4%
Cash flow / debt	12.0%	13.6%	12.7%	13.3%	14.4%	14.0%	15.5%
EBIT interest coverage	2.36	2.48	2.39	2.47	2.48	2.35	2.69
Total dividend payout ratio	1.4%	1.4%	54.2%	53.0%	79.6%	97.1%	73.1%

2015 Summary

- Overall, key credit metrics remain reasonable for the current rating category.
- Operating cash flow remains predictable and has improved over time, on an annual basis, in line with an increasing rate base. Operating cash flow was slightly lower in 9M 2015 because of higher storage and transportation revenues in 9M 2014, which benefitted from the March 2014 OEB decision (resulted in certain 2012 revenues realized from the optimization of upstream transportation contacts as utility earnings being included in 9M 2014), and higher cash taxes paid in 9M 2015.
- Capex has been relatively high because of spending on the 2015 Dawn-Parkway expansion project (in service Q4 2015) and the Burlington-Oakville project (expected in service H2 2016). The capital cost of the 2015 Dawn-Parkway was $432 million, and the capital cost of the Burlington-Oakville project is expected to be $120 million.
- Dividends are primarily used to maintain Union's capital structure in line with regulatory-approved levels (64% debt and 36% equity). Dividends paid were $2 million for 9M 2015 and 9M 2014, reflecting ongoing preferred share dividends. Common stock dividends are paid on an annual basis, usually in the fourth quarter, and totalled approximately $100 million in 2014.
- Union has generated free cash flow deficits for the past five years, and this is expected to continue in the medium term because of higher capex for storage and transmission expansion projects.
- During 9M 2015, Free cash flow deficits were offset by positive changes in non-cash working capital items, caused by seasonal lower inventory levels and over collection of gas costs from customers, which reduced the Company's reliance on debt financing.

2016 Outlook

- Capex for 2016 is expected to be approximately $1.0 billion, largely associated with Dawn-Parkway expansions. Financing of the capex program is not expected to have a material impact on the Company's financial profile. DBRS expects the Company to maintain its leverage in line with the OEB-approved capital structure by prudently managing debt levels and dividend payouts. Union's expansion projects also benefit from the regulated cost of service framework.

Financial Profile (CONTINUED)

- The 2016 and 2017 Dawn-Parkway expansions have been approved for construction and rate recovery. The total cost of both projects is over $1 billion, and their aim is to increase capacity along the Dawn-Parkway system to meet market interest for supply. Customers for this capacity include Enbridge, Gaz Metro, TransCanada and others.

Liquidity and Long-Term Debt Maturities

Credit Facility

As at September 30, 2015 ($ millions)	Maturity Date	Committed	CP	Available
Five-year syndicated credit facility	2019	500	0	500

- The Company's credit facility is mainly used to backstop its $500 million commercial paper program, which supports Company's working capital needs.
- DBRS views Union's liquidity as sufficient for its working capital funding requirements.
- Union is generally subject to seasonality as a part of its business, and as a result, its short-term debt and its gas inventory typically peak in the first and fourth quarters of every year.
- The facility contains a maximum 75% debt-to-capital covenant and includes a provision requiring the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. As at September 30, 2015, the Company was in compliance with these covenants.

Debt Maturity Schedule

As at September 30, 2015 ($ millions)	2016	2017	2018	2019	Thereafter	Total
MTNs and Debentures	200	125	400	0	2,415	3,140

- The Company's debt maturity is well spread out, and $200 million of long-term debt is due in 2016. DBRS expects the refinancing risk to be minimal, given Union's good access to debt capital markets. The amounts due from 2016 to 2019 remain modest and are also within the financing capacity of the Company.
- In September 2015, the Company issued $200 million of 3.19% medium-term note debentures due September 2025 and $250 million of 4.20% Series 12 medium-term note debentures due June 2044.
- Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants. Therefore, the Company can have a maximum total debt-to-capitalization of 75%, and any incremental debt is subject to a minimum interest coverage test of 2.0x. As at September 30, 2015, the Company was in compliance with all covenants.

Liquidity and Long-Term Debt Maturities (CONTINUED)

Long-Term Debt

($ millions)		September 30, 2015	December 31, 2014
7.90%	1994 Series debentures, due February 24, 2014	-	-
11.50%	1990 Series debentures, due August 28, 2015	-	150
4.64%	Series 5, due June 30, 2016	200	200
9.70%	1992 Series II debentures, due November 6, 2017	125	125
5.35%	Series 6, due April 27, 2018	200	200
8.75%	1993 Series debentures, due August 3, 2018	125	125
8.65%	Senior debentures, due October 19, 2018	75	75
2.76%	Series 11, due June 2, 2021	200	200
4.85%	Series 6, due April 25, 2022	125	125
3.79%	Series 10 due July 10, 2023	250	250
3.19%	Series 13, due September 17, 2025	200	-
8.65%	1995 Series debentures, due November 10, 2025	125	125
5.46%	Series 6, due September 11, 2036	165	165
6.05%	Series 7, due September 2, 2038	300	300
5.20%	Series 8, due July 23, 2040	250	250
4.88%	Series 9 due June 21, 2041	300	300
4.20%	Series 12 due June 2, 2044	500	250
		3,140	**2,840**
Less: unamortized debt discount		(7)	(3)
		3,133	**2,837**
Less: current portion		(200)	(150)
		2,933	**2,687**

Regulation

Regulatory Overview

Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB. (Refer to "Assessment of Union's Regulatory Environment" on page 9). The regulatory environment in Ontario for natural gas distributors is viewed as reasonable.

Gas Distribution

- Union's distribution rates are set under a multi-year IR framework with rebasing under the COS framework occurring between the IR periods.
- From 2014 to 2018, Union will be regulated under the IR framework. Under this framework, Union will be able to increase rates annually by an inflation factor, which will be offset by a productivity factor of 60%; thus, the annual net rate escalator in each year is 40% of inflation.
- For 2014 to 2018, the Company has an approved ROE of 8.93% and a deemed equity component of 36%. The earnings sharing mechanism permits Union to fully retain the ROE from regulated operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.
- The Company is allowed to pass through gas commodity, upstream transportation and demand side management costs to customers. It will also be allowed additional pass-through of costs associated with major capital investments and certain fuel variances, an allowance for unexpected cost changes that are outside of management's control, equal sharing of taxes between customers and an earnings sharing mechanism.
- On December 9, 2015, Union filed an application to for the quarterly rate adjustment mechanism commencing Jan 1, 2016. The application also implemented rates approved by the OEB in Union's 2016 Rates proceeding (Decision and Rate Order issued December 3, 2015). The combined annual bill impacts for a typical residential customer range from a decrease of $49.48 to $47.76 depending on location. The application was approved on December 22, 2015.

Gas Storage

- Storage services outside Union's franchise area or new storage services to customers in the franchise area are not regulated by the OEB. This accounts for approximately one-third of storage capacity.
- Storage within Union Gas's service area is regulated under the COS regulation.

Regulation (CONTINUED)

Upstream Regulation – Local Distribution Companies (LDCs) settlement

- In October 2014, TransCanada filed an application with the National Energy Board to convert one of its mainline gas pipelines to transport oil (part of the Energy East Project) and construct a new natural gas pipeline to replace the capacity in eastern Ontario and Québec (Eastern Mainline Project)
- In August 2015, it was announced that TransCanada had reached an agreement in principle with Eastern LDCs, including Union, addressing supply concerns caused by the Energy East and Eastern Mainline projects. Keys terms stated that TransCanada will size the Eastern Mainline Project to meet all firm service requirements resulting from 2016 and 2017 new capacity open seasons plus approximately 50 mmcf/d of additional capacity. In addition, TransCanada agreed to ensure a long-term benefit to natural gas consumers in Eastern Ontario and Québec of at least $100 million through to 2050.
- In October 2015, TransCanada, Union Gas, Enbridge Gas Distribution Inc. and Gaz Métro Limited Partnership executed a definitive agreement that protects the interests of natural gas customers and markets in Ontario and Québec, which aligned with the previously mentioned agreement.

Assessment of Union's Regulatory Environment

Criteria	Score	Analysis
Deemed Equity	Excellent Good Satisfactory **Below Average** Poor	The OEB allows Union to have a deemed equity of 36%, which is consistent with the other gas distributors in Ontario. However, deemed equity is below peer utilities in Canada and the United States.
Allowed ROE	**Excellent** Good Satisfactory Below Average Poor	For 2014 to 2018, the Company has an approved ROE of 8.93%. In addition, the earnings sharing mechanism permits Union to fully retain the ROE from regulated operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.
Energy Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	The Company is able to fully pass through gas commodity and upstream transportation costs on a quarterly basis and demand side management costs on an annual basis. It is also allowed additional pass-through of costs associated with major capital investments and certain fuel variances, an allowance for unexpected cost changes that are outside of management's control, equal sharing of taxes between customers and an earnings sharing mechanism.
Capital Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Major capital costs are pre-approved by the regulator and added to rate base after the completion. Other capital spending after the base year will not be approved until the next rate application and approval of the rate base.
COS vs. IRM	Excellent Good **Satisfactory** Below Average Poor	Union's distribution rates are set under a five-year IR framework with rebasing under the COS framework between the IR periods. Under this framework, Union will be able to increase rates annually by an inflation factor, which will be offset by a productivity factor of 60% of inflation; thus, the annual net rate escalator in each year is 40% of inflation.
Political Interference	Excellent **Good** Satisfactory Below Average Poor	There is low degree of government influence. Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB.
Retail Rate	Excellent **Good** Satisfactory Below Average Poor	In the natural gas sector, the OEB regulates Ontario's natural gas utilities, which are required to submit the rates they propose to charge their customers to the Board for review and approval. The cost of natural gas distributed by Union Gas is set by the OEB at 9.4846 ¢/m3 (January 2016), which is lower than rates charged by Enbridge (11.7485 ¢/m3) and generally lower compared with other provinces in Canada. Rates are dictated by commodity costs and transportation tolls on pipelines. Economic environment in Ontario is considered good.
Stranded Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	Union has very limited history of stranded costs.
Rate Freeze	**Excellent** Good Satisfactory Below Average Poor	Rates are based on the market price of natural gas plus distribution and servicing costs. Rates have not been frozen within the past decade.
Market Structure (Deregulation)	Excellent **Satisfactory** Poor	The natural gas sector is partially deregulated such that a portion of consumers can chose their supplier. Union Gas does not produce or extract natural gas but provides storage and transportation services. There is reasonable regulatory oversight on distribution rates.

Balance Sheet ($ millions)

	Sep. 30	Dec. 31			Sep. 30	Dec. 31	
	2015	2014	2013		2015	2014	2013
Assets				**Liabilities & Equity**			
Cash & equivalents	33	20	10	S.T. borrowings	0	318	336
Accounts receivable	660	1,135	867	Accounts payable	886	1,117	874
Inventories	294	239	160	Current portion L.T.D.	200	150	150
Income tax receivables & other	0	17	8	Deferred taxes & other	16	25	0
Total Current Assets	**987**	**1,411**	**1,045**	**Total Current Liab.**	**1,102**	**1,610**	**1,360**
Net fixed assets	5,476	5,154	4,847	Long-term debt	2,933	2,687	2,387
Regulatory assets & others	543	480	483	Asset retirement obligations	380	368	328
				Deferred income taxes	447	417	408
				Regulatory liabilities & others	531	497	484
				Minority interest	0	8	9
				Preferred shares	110	110	110
				Common equity	1,503	1,348	1,289
Total Assets	**7,006**	**7,045**	**6,375**	**Total Liab. & SE**	**7,006**	**7,045**	**6,375**

	9 mos. Ending Sep. 30		12 mos. Ending Sep 30	12 mos. Ending Dec. 31			
Balance Sheet and Liquidity Capital Ratios	2015	2014	2015	2014	2013	2012	2011
Current ratio	0.90	1.00	0.90	0.88	0.77	0.74	0.79
Debt / capital	63.6%	63.4%	63.6%	65.6%	64.7%	63.9%	63.9%
Lease-adjusted debt / capital	63.8%	63.7%	63.8%	65.5%	65.1%	64.2%	63.4%
Cash flow / debt	12.0%	13.6%	12.7%	13.3%	14.4%	14.0%	15.5%
Lease-adjusted cash flow / debt	11.9%	13.5%	12.7%	13.5%	14.3%	14.0%	16.0%
(Cash flow - dividends) / capex	0.59	1.06	0.45	0.67	0.71	0.77	0.92
Total dividend payout ratio	1.4%	1.4%	54.2%	53.0%	79.6%	97.1%	73.1%
Coverage Ratios (times)							
EBIT interest coverage	2.36	2.48	2.39	2.47	2.48	2.35	2.69
EBITDA interest coverage	3.78	3.84	3.79	3.83	3.81	3.71	4.03
Fixed-charge coverage	2.30	2.41	2.31	2.39	2.40	2.27	2.62
Lease-adjusted EBIT interest coverage	2.35	2.46	2.37	2.46	2.46	2.33	2.67
Profitability Ratios							
EBITDA margin	57.3%	57.1%	56.3%	56.2%	55.8%	56.5%	58.3%
EBIT margin	35.9%	36.8%	35.5%	36.2%	36.4%	35.7%	38.9%
Profit margin	18.0%	18.3%	18.0%	18.2%	18.2%	16.6%	19.0%
Return on common equity	12.5%	13.9%	12.7%	14.5%	15.5%	14.8%	15.9%
Return on capital 1	5.5%	6.2%	5.7%	6.1%	6.5%	6.5%	7.2%

1 Adjusted for accumulated other comprehensive income.

Rating History

	Current	2015	2014	2013	2012	2011
Issuer Rating	A	A	A	A	A	NR
Unsecured Debentures/Medium-Term Note Debentures	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cumulative Redeemable Preferred Shares	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Previous Action

- Confirmed, February 12, 2015.

Related Research

- DBRS Rates Union Gas $450 Million Notes Issue at "A," Stable Trend, September 17, 2015.
- DBRS Confirms Ratings of Union Gas Limited, February 12, 2015.

Commercial Paper Limited

- $500 million.

Previous Report

- Union Gas Limited, Rating Report, February 12, 2015.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Rating Report

Union Gas Limited

DBRS

Insight beyond the rating.

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures/Medium-Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating Update

On February 9, 2017, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debentures/Medium-Term Note Debentures rating of Union Gas Limited (Union or the Company) at "A," the Company's Commercial Paper rating at R-1 (low) and its Cumulative Redeemable Preferred Shares rating at Pfd-2. All trends are Stable. The rating confirmations reflect Union's relatively low-risk gas distribution business, which operates under a reasonable regulatory framework in an economically stable service territory with a large growing customer base.

DBRS rates Union on a stand-alone basis and does not assume any credit support from its ultimate parent, Spectra Energy Capital, LLC (Spectra, rated BBB, Stable). DBRS has determined that the merger between Enbridge Inc. (rated BBB (high), Under Review with Developing Implications) and Spectra, which was announced in September 2016, does not have an impact on the stand-alone credit quality of Union. (Please refer to the DBRS press release "DBRS Confirms Spectra Energy Capital, LLC and Rated Subsidiaries, Removes UR-Dev. Status," dated September 8, 2016.)

DBRS's assessment of Union's business risk considers the reasonable cost-of-service-based regulatory framework in Ontario, which provides a majority of the Company's earnings. Union operates under a five-year incentive regulation framework (IR; 2014 to 2018), which allows a return on equity (ROE) of 8.93% and provides predictable cash flows. Natural gas supply costs are passed through to customers, mitigating commodity price risk, with annual rate escalation indexed at 40% of inflation. Major capital expenditures are pre-approved by the Ontario Energy Board for inclusion in rates as projects are completed and placed in service. DBRS notes that, although the Company's regulated distribution and storage business accounts for the bulk of the Company's earnings, earnings generated from its unregulated storage business (approximately 13% of EBIT in 2015) could expose the Company to some earnings volatility. DBRS views this segment as higher risk than the regulated distribution and storage business because of the impact of seasonality on storage demand and rates.

Union's credit metrics have been pressured over the past few years because of high capex spending. DBRS expects Union's capital spending program primarily on transmission expansions to be relatively high for the full year 2016 (approximately $1.0 billion in 2016 compared with approximately $750 million in 2015). As major projects (2016 Dawn-Parkway and the Burlington to Oakville) were placed in service in Q4 2016, capex for 2017 is expected to be slightly lower. DBRS expects the incremental full-year cash flow from projects placed in service and lower capex needs to result in a gradual improvement in credit metrics in 2017. In the medium term, the ratings could come under pressure should the Company fail to maintain its debt-to-capital ratio in line with the regulatory capital structure of 64% debt and 36% equity or should cash flow-to-debt remain below the 15% level on a sustained basis.

Financial Information

	9 mos. Ending Sept. 30		12 mos. Ending Sept. 30	12 mos. Ending Dec. 31			
($ millions where applicable)	2016	2015	2016	2015	2014	2013	2012
Cash flow / debt	11.9%	12.0%	11.4%	11.0%	13.4%	14.4%	14.0%
Lease-adjusted debt / capital	66.3%	63.9%	66.3%	65.8%	65.8%	65.1%	64.2%
EBIT interest coverage (times)	2.38	2.36	2.28	2.27	2.43	2.48	2.35

Issuer Description

Union Gas Limited is a utility that provides natural gas distribution, transmission and storage services in Southwestern, Northern and Eastern Ontario, serving approximately 1.4 million customers. Union Gas' common stock is held by Great Lakes Basin Energy L.P., a wholly owned limited partnership of Westcoast Energy Inc. (rated A (low)). Westcoast is indirectly owned by Spectra Energy Capital, LLC (rated BBB).

Rating Considerations

Strengths

1. Reasonable regulatory environment

Union's gas regulated distribution business operates under a reasonable regulatory environment, which provides predictable cash flows and allows the Company to earn a reasonable return on its investments. The Company currently operates under a five-year IR framework (2014 to 2018), with rebasing under the cost-of-service (COS) framework in between. Union's regulated distribution business is not exposed to commodity price risk, as gas supply costs are adjusted quarterly and passed through to customers.

2. Large customer base and strong franchise

Union's cash flow is supported by a large customer base (1.4 million), which is growing at a steady rate, making Union one of the largest natural gas distributors in Canada. Union provides transportation and storage services to almost all, and distribution to most, gas-fired generation plants in Ontario. The Company's Dawn storage facility (163 billion cubic feet (bcf) capacity) acts as a gateway for Marcellus/Utica gas supply and is strategically connected to key pipelines transporting natural gas to major Canadian and U.S. markets. Long-term demand for natural gas in Ontario is expected to remain relatively stable with continued growth in peak day demands. Union Gas' transmission system has an effective peak daily demand capacity of 7.2 bcf per day. Moreover, the Company's franchise area covers more than 400 communities in Northern, Southwestern and Eastern Ontario. Approximately 50% of Union's revenue is generated from residential customers, a segment that is less exposed to economic downturns.

3. Growing rate base

Union's regulated rate base has grown in the past few years with the addition of major transmission and expansion of storage assets to reach over $ 4.0 billion in 2016. The growing rate base is expected to benefit earnings and cash flow for the Company going forward.

Challenges

1. Consistent free cash flow deficits

Union has generated free cash flow deficits because of higher capex primarily for transmission expansions. This is expected to moderate in the next two years as several projects are completed and placed in service. DBRS expects the Company to finance the deficits prudently by managing debt levels, dividend payouts and infusion of equity in order to maintain an improved cash flow coverage and its debt-to-capital ratio within regulatory levels.

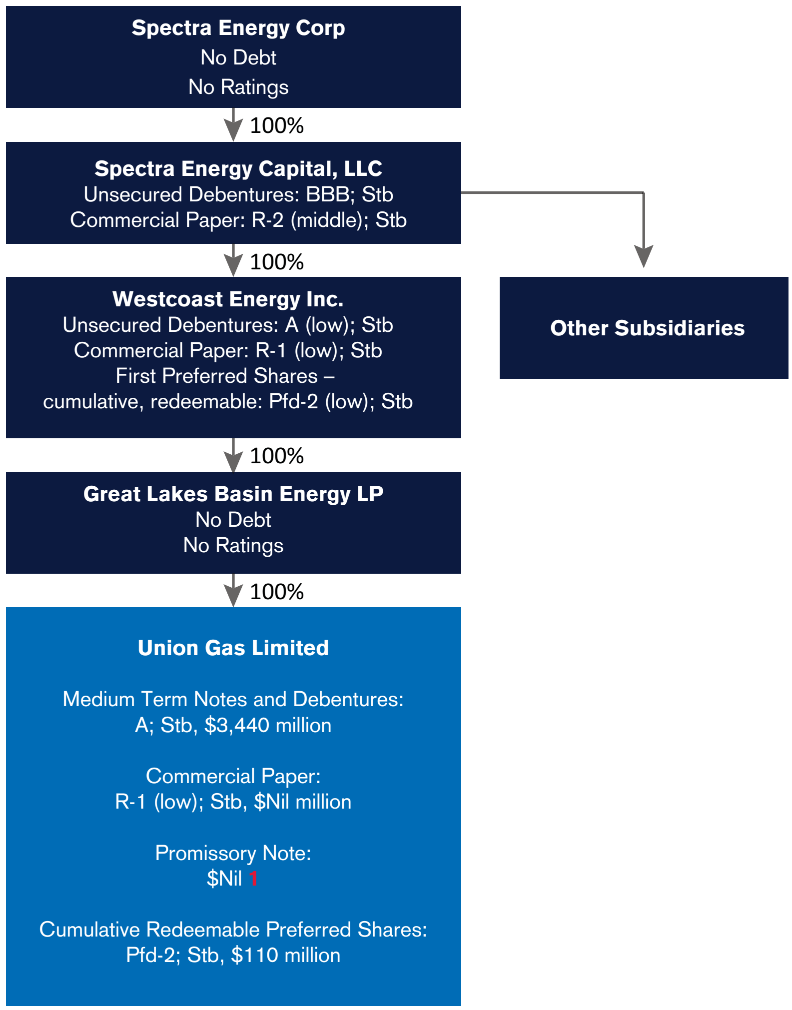
2. Seasonality and volume risk

The natural gas distribution business is subject to seasonality related to volume-based rates and the significant effect of the winter heating season on volumes. Union is exposed to a degree of demand risk, since its rates are based on forecast volumes, which are sensitive to changes in weather. Natural gas rates approved by the OEB assume normal weather conditions. Since a majority of the gas distributed by Union to the residential and commercial markets is used for space heating and is charged using volume-based rates, differences from normal weather could have a significant effect on the consumption of gas and on the Company's financial results. However, DBRS notes that under the IR framework, Union is allowed to recover shortfalls relative to normalized consumption on an annual basis with a one-year lag. The Company has also increased fixed monthly charges for residential and small commercial customers to partially mitigate the impact of volume changes.

3. Earnings volatility of non-regulated storage

Union's non-regulated storage earnings add some volatility in earnings. DBRS views this segment as higher risk than the regulated distribution and storage business because of the impact of seasonality on storage demand and rates. In 2015, Union's non-regulated storage business accounted for approximately 13% of EBIT (12% in 2014).

Simplified Organizational Chart (as at September 30, 2016)



1 The Company has a promissory note to borrow up to $150 million from Great Lakes Basin Energy L.P. on an unsecured basis.

Earnings and Outlook

	9 mos. Ending Sept. 30		12 mos. Ending Sept. 30	12 mos. Ending Dec. 31			
($ millions where applicable)	**2016**	**2015**	**2016**	**2015**	**2014**	**2013**	**2012**
Gas distribution margin	585	584	801	800	778	772	727
Storage and transportation revenues	206	179	266	239	266	252	269
Ancillary revenue	12	15	23	26	21	26	28
Operating revenue	803	778	1,090	1,065	1,065	1,050	1,024
Total operating expense	520	499	713	692	677	668	658
EBITDA	464	446	615	597	600	586	579
EBIT	283	279	377	373	388	382	366
Gross interest expense	119	118	165	164	160	154	156
Earning before taxes	164	161	219	216	232	228	210
Core net income	152	140	200	188	196	191	170
Reported net income	152	140	200	188	195	207	170
Return on common equity	12.6%	12.9%	12.4%	13.0%	14.6%	15.5%	14.8%
Distribution rate base 1	n/a	n/a	n/a	4,228	3,976	3,784	3,749

1 n/a: not available on a quarterly basis.

2016 Summary

- Approximately 90% of Union's earnings are generated from its regulated gas distribution, storage and transmission businesses. The balance is generated from the Company's unregulated storage business, which carries some earnings volatility resulting from seasonal fluctuation in demand and rates.
- Earnings before Interest and Taxes (EBIT) were marginally higher in the first nine months of 2016 (9M 2016) relative to 9M 2015 as a result incremental revenue from the 2015 Dawn-Parkway expansion project and higher storage pricing, partly offset by increased depreciation from projects placed into service.

2017 Outlook

- DBRS anticipates that Union's earnings will likely increase modestly in 2017 as a result of rate base growth, distribution rate increases and customer growth.
- Although weather conditions are unpredictable, DBRS expects ongoing energy conservation programs, including the Company's Demand Side Management Initiative, to have a modest impact on customer usage. This will likely be offset by modest annual customer growth of approximately 1% to 2%.

Financial Profile

	9 mos. Ending Sept. 30		12 mos. Ending Sept. 30	12 mos. Ending Dec. 31			
($ millions where applicable)	**2016**	**2015**	**2016**	**2015**	**2014**	**2013**	**2012**
Core net income	152	140	200	188	196	191	170
Depreciation & amortization	181	167	238	224	212	204	213
Deferred income taxes and other	4	(26)	(10)	(40)	13	19	(8)
Cash flow (bef. working cap. changes)	**337**	**281**	**428**	**372**	**421**	**414**	**375**
Dividends paid	(2)	(2)	(53)	(53)	(103)	(152)	(165)
Capital expenditures	(756)	(474)	(983)	(701)	(474)	(370)	(271)
Free cash flow (bef. working cap. changes)	**(421)**	**(195)**	**(608)**	**(382)**	**(156)**	**(108)**	**(61)**
Changes in non-cash work. cap. items	3	232	(100)	129	(116)	(94)	58
Net Free Cash Flow	**(418)**	**37**	**(708)**	**(253)**	**(272)**	**(202)**	**(3)**
Acquisitions & long-term investments	0	0	0	0	0	0	0
Short-term investments	0	0	0	0	0	0	0
Proceeds on asset sales	0	0	0	0	0	0	0
Net equity change	0	0	0	0	0	0	0
Net debt change	386	(22)	648	240	282	203	5
Other	42	(2)	42	(2)	0	0	0
Change in cash	**10**	**13**	**(18)**	**(15)**	**10**	**1**	**2**
Total debt	3,770	3,133	3,770	3,384	3,144	2,873	2,670
Cash and equivalents	15	33	15	5	20	10	9
Lease-adjusted debt / capital	66.3%	63.9%	66.3%	65.8%	65.8%	65.1%	64.2%
Cash flow / debt	11.9%	12.0%	11.4%	11.0%	13.4%	14.4%	14.0%
EBIT interest coverage (times)	2.38	2.36	2.28	2.27	2.43	2.48	2.35
Total dividend payout ratio	1.3%	1.4%	26.5%	28.2%	52.6%	79.6%	97.1%

2016 Summary

- Union's key credit metrics have been pressured in the past few years because of the Company's capital program.
- Operating cash flow remains reasonably predictable and has generally improved in line with an increasing rate base. Operating cash flow was slightly higher in 9M 2016 relative to 9M 2015 because of higher storage and transportation revenues.
- Capex has been relatively high because of spending on the 2016 Dawn-Parkway expansion project ($400 million; in service Q4 2016) and the Burlington-Oakville project ($120 million; in service Q4 2016). Full-year capex for 2016 is expected to be approximately $1.0 billion.
- Union Gas has a flexible dividend policy. Dividends are primarily used to maintain Union's capital structure in line with regulatory-approved levels (64% debt and 36% equity). Dividends paid were $2 million for 9M 2016 and 9M 2015, reflecting ongoing preferred share dividends. Common stock dividends to Union's parent are paid on an annual basis, usually in the fourth quarter, and totalled $53 million in 2015.
- Union has generated free cash flow (before working capital changes) deficits because of high capex primarily for transmission expansion projects. This is expected to moderate in the medium term as projects are completed and placed in service.

2017 Outlook

- The 2016 financial plan estimated $500 million of expansion capex for 2017. An updated 2017 financial plan has not yet been released. Expansion capex for 2017 will include the 2017 Dawn-Parkway expansion and Panhandle Reinforcement project. Union's current expansion projects benefit from the regulated utility COS framework. At a total cost of $620 million, the 2017 Dawn-Parkway expansion has been approved for construction and rate recovery. The Dawn-Parkway expansions aim to increase capacity along the Dawn-Parkway system linking gas supply from the Marcellus/Utica to meet market demand. Customers for this capacity include Enbridge, Gaz Metro, TransCanada and others.
- The $265 million Panhandle Reinforcement project application was filed for OEB approval in June 2016, and approval is expected in H1 2017. The purpose of the project is to increase capacity on the Panhandle system to serve market growth in Southern Ontario.
- DBRS expects the Company to maintain its leverage in line with the OEB-approved capital structure by prudently managing debt levels, dividend payouts and infusion of equity.

Liquidity and Long-Term Debt Maturities

Credit Facility

As at September 30, 2016 ($ millions)	Maturity Date	Committed	CP	Available
Five-year syndicated credit facility	2021	700	0	700

- The Company's credit facility is mainly used to backstop its $700 million commercial paper program, which supports the Company's working capital needs.
- DBRS views Union's liquidity as sufficient for its working capital funding requirements.
- Union is generally subject to seasonality as a part of its business, and as a result, its short-term debt and its gas inventory typically peak in the first and fourth quarters of every year.
- The facility contains a maximum 75% debt-to-capital covenant and includes a provision requiring the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. As at September 30, 2016, the Company was in compliance with these covenants.

Debt Maturity Schedule

As at September 30, 2016 ($ millions)	2017	2018	2019	2020	Thereafter	Total
MTNs and Debentures	125	400	0	0	2,915	3,440

- The Company's debt maturity is well spread out and manageable. DBRS expects the refinancing risk to be minimal, given Union's good access to debt capital markets.
- In May 2016, the Company issued $250 million of 2.81% medium-term note debentures due June 2026 and $250 million of 3.80% medium-term note debentures due June 2046.
- Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants. Therefore, the Company can have a maximum total debt-to-capitalization of 75%, and any incremental debt is subject to a minimum interest coverage test of 2.0 times (x). As at September 30, 2016, the Company was in compliance with all covenants.

Regulation

Regulatory Overview

- Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB (refer to section titled "Assessment of Union's Regulatory Environment"). The regulatory environment in Ontario for natural gas distributors is viewed as reasonable.

Gas Distribution

- Union's distribution rates are set under a multi-year IR framework, with rebasing under the COS framework occurring between the IR periods.
- From 2014 to 2018, Union will be regulated under the IR framework. Under this framework, the Company will be able to increase rates annually by an inflation factor, which will be offset by a productivity factor of 60%; thus, the annual net rate escalator in each year is 40% of inflation.
- For 2014 to 2018, the Company has an approved ROE of 8.93% and a deemed equity component of 36%. The earnings sharing mechanism permits Union to fully retain the ROE from regulated operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.
- The Company is allowed to pass through gas commodity, upstream transportation and demand side management costs to customers. It will also be allowed additional pass-through of costs associated with major capital investments and certain fuel variances, an allowance for unexpected cost changes that are outside of management's control, equal sharing of taxes between customers and an earnings sharing mechanism.
- On December 9, 2016, Union filed an application to for the quarterly rate adjustment mechanism commencing January 1, 2017. The application also implemented rates approved by the OEB in Union's 2017 Rates proceeding (Decision and Rate Order issued December 8, 2016) and rates previously approved on an interim basis to recover the cost consequences of Union's proposed cap-and-trade compliance plan (Interim Rate Order issued November 25, 2016). The combined annual bill increase for a typical residential customer ranged from $10.46 to $99.55, depending on location. The application was approved on December 21, 2016.

Gas Storage

- Storage services outside Union's franchise area or new storage services to customers in the franchise area are not regulated by the OEB. This accounts for approximately one-third of storage capacity.
- Storage within Union's service area is regulated under the COS regulation.

Upstream Regulation – Local Distribution Companies (LDCs) settlement

- In October 2014, TransCanada filed an application with the National Energy Board (NEB) to convert one of its mainline gas pipelines to transport oil (part of the Energy East Project) and construct a new natural gas pipeline to replace the capacity in eastern Ontario and Québec (Eastern Mainline Project).
- In August 2015, it was announced that TransCanada had reached an agreement in principle with Eastern LDCs, including Union, addressing supply concerns caused by the Energy East and Eastern Mainline projects. Keys terms stated that TransCanada will size the Eastern Mainline Project to meet all firm service requirements resulting from 2016 and 2017 new capacity open seasons plus approximately 50 mmcf/d of additional capacity. In addition, TransCanada agreed to ensure a long-term benefit to natural gas consumers in Eastern Ontario and Québec of at least $100 million through to 2050.
- In October 2015, TransCanada, Union Gas, Enbridge Gas Distribution Inc. and Gaz Métro Limited Partnership executed a definitive agreement that protects the interests of natural gas customers and markets in Ontario and Québec, which aligned with the previously mentioned agreement.
- On January 27, 2017, the NEB announced that a new hearing panel was assigned to review the Energy East and Eastern Mainline applications and that the new hearing panel had voided all decisions made by the previous hearing panel. The hearings for these applications have restarted from the beginning.

Assessment of Union's Regulatory Environment

Criteria	Score	Analysis
Deemed Equity Ratio	Excellent Good Satisfactory **Below Average** Poor	The OEB allows Union to have a deemed equity of 36%, which is consistent with the other gas distributors in Ontario. However, deemed equity is below peer utilities in Canada and the United States.
Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	For 2014 to 2018, the Company has an approved ROE of 8.93%. In addition, the earnings sharing mechanism permits Union to fully retain the ROE from regulated operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.
Energy Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	The Company is able to fully pass through gas commodity and upstream transportation costs on a quarterly basis and demand side management costs on an annual basis. It is also allowed additional pass-through of costs associated with major capital investments and certain fuel variances, an allowance for unexpected cost changes that are outside of management's control, equal sharing of taxes between customers and an earnings sharing mechanism.
Capital and Operating Cost Recoveries	Excellent **Good** Satisfactory Below Average Poor	Major capital costs are pre-approved by the regulator and added to the rate base after completion. Other capital spending after the base year will not be approved until the next rate application and approval of the rate base.
COS vs. IRM	Excellent Good **Satisfactory** Below Average Poor	Union's distribution rates are set under a five-year IR framework, with rebasing under the COS framework between the IR periods. Under this framework, Union will be able to increase rates annually by an inflation factor, which will be offset by a productivity factor of 60% of inflation; thus, the annual net rate escalator in each year is 40% of inflation.
Political Interference	Excellent **Good** Satisfactory Below Average Poor	There is low degree of government influence. Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB.
Stranded Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	Union has very limited history of stranded costs.
Rate Freeze	**Excellent** Good Satisfactory Below Average Poor	Rates are based on the market price of natural gas plus distribution and servicing costs. Rates have not been frozen within the past decade.

Union Gas Limited

Balance Sheet ($ millions)	Sept. 30 2016	Dec. 31 2015	Dec. 31 2014		Sept. 30 2016	Dec. 31 2015	Dec. 31 2014
Assets				**Liabilities & Equity**			
Cash & equivalents	15	5	20	S.T. borrowings	351	263	318
Accounts receivable	556	650	1,135	Accounts payable	758	793	1,117
Inventories	280	297	239	Current portion L.T.D.	0	200	150
Income tax receivables & other	32	24	17	Deferred taxes & other	0	0	25
Total Current Assets	**883**	**976**	**1,411**	**Total Current Liab.**	**1,109**	**1,256**	**1,610**
Net fixed assets	6,327	5,678	5,154	Long-term debt	3,419	2,921	2,676
Regulatory assets & others	604	536	469	Asset retirement obligations	455	440	368
				Deferred income taxes	505	451	417
				Regulatory liabilities & others	553	509	497
				Minority interest	0	0	8
				Preferred shares	110	110	110
				Common equity	1,663	1,503	1,348
Total Assets	**7,814**	**7,190**	**7,034**	**Total Liab. & SE**	**7,814**	**7,190**	**7,034**

Balance Sheet and Liquidity Capital Ratios	9 mos. Ending Sept. 30 2016	9 mos. Ending Sept. 30 2015	12 mos. Ending Sept. 30 2016	12 mos. Ending Dec. 31 2015	12 mos. Ending Dec. 31 2014	12 mos. Ending Dec. 31 2013	12 mos. Ending Dec. 31 2012
Current ratio (times)	0.80	0.90	0.80	0.78	0.88	0.77	0.74
Debt / capital	66.1%	63.6%	66.1%	65.4%	65.5%	64.7%	63.9%
Lease-adjusted debt / capital	66.3%	63.9%	66.3%	65.8%	65.8%	65.1%	64.2%
Cash flow / debt	11.9%	12.0%	11.4%	11.0%	13.4%	14.4%	14.0%
Lease-adjusted cash flow / debt	11.9%	11.9%	11.3%	10.9%	13.3%	14.3%	13.9%
(Cash flow - dividends) / capex (times)	0.44	0.59	0.38	0.46	0.67	0.71	0.77
Total dividend payout ratio	1.3%	1.4%	26.5%	28.2%	52.6%	79.6%	97.1%
Coverage Ratios (times)							
EBIT interest coverage	2.38	2.36	2.28	2.27	2.43	2.48	2.35
EBITDA interest coverage	3.90	3.78	3.73	3.64	3.75	3.81	3.71
Fixed-charge coverage	2.31	2.30	2.22	2.20	2.35	2.40	2.27
Lease-adjusted EBIT interest coverage	2.36	2.35	2.27	2.26	2.41	2.46	2.33
Profitability Ratios							
EBITDA margin	57.8%	57.3%	56.4%	56.1%	56.3%	55.8%	56.5%
EBIT margin	35.2%	35.9%	34.6%	35.0%	36.4%	36.4%	35.7%
Profit margin	18.9%	18.0%	18.3%	17.7%	18.4%	18.2%	16.6%
Return on common equity	12.6%	12.9%	12.4%	13.0%	14.6%	15.5%	14.8%
Return on capital	4.8%	5.6%	5.2%	5.5%	6.1%	6.5%	6.4%

Rating History

	Current	2016	2015	2014	2013	2012
Issuer Rating	A	A	A	A	A	A
Unsecured Debentures/Medium-Term Note	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cumulative Redeemable Preferred Shares	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Previous Action

- Confirmed, September 8, 2016.

Related Research

- "DBRS Confirms Spectra Energy Capital, LLC and Rated Subsidiaries, Removes UR-Dev. Status," September 8, 2016.
- "DBRS Places Spectra Energy Capital, LLC and Rated Subsidiaries Under Review with Developing Implications," September 6, 2016.
- "DBRS Confirms Ratings of Union Gas Limited," February 9, 2016.

Commercial Paper Limit

- $700 million

Previous Report

- Union Gas Limited: Rating Report, February 17, 2016.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Rating Report

Union Gas Limited

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DBRS

Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures/Medium-Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating Update

On February 7, 2018, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debentures/Medium-Term Note Debentures rating of Union Gas Limited (Union or the Company) at "A," the Company's Commercial Paper rating at R-1 (low) and its Cumulative Redeemable Preferred Shares rating at Pfd-2. All trends are Stable. The rating confirmations largely reflect Union's relatively low-risk gas distribution business, which operates under a supportive regulatory framework in an economically stable service territory with a large and growing customer base.

DBRS rates Union on a stand-alone basis and does not assume any credit support from its ultimate parent, Enbridge Inc. (Enbridge; rated BBB (high), Stable by DBRS). On November 2, 2017, Union and Enbridge Gas Distribution Inc. (EGD; rated "A," Stable by DBRS) filed a Mergers, Acquisitions, Amalgamation and Divestitures application with the Ontario Energy Board (OEB) to amalgamate. Enbridge expects the regulatory review to take the better part of 2018. Enbridge will seek approval from its Board of Directors to proceed with the amalgamation based on an assessment of the final regulatory approvals from the OEB, which is anticipated to take place in Q3 2018. Should the amalgamation not proceed, Union will file a new five-year incentive regulation (IR) framework application for 2019, and beyond. DBRS will continue to monitor the progress of the application as more information becomes available.

DBRS's assessment of the Company's business risk considers the supportive cost of service (COS)-based regulatory framework in Ontario, which provides a vast majority of Union's earnings. The Company has operated under an IR framework from 2014 to 2018, which allowed for a return on equity (ROE) of 8.93% and provided predictable cash flows. Natural gas supply costs are passed through to customers, mitigating commodity price risk, with annual rate escalation indexed at 40% of inflation. Major capital expenditures (capex) are pre-approved by the OEB for inclusion in rates as projects are completed and placed in service. DBRS notes that, although the Company's regulated distribution and storage business accounts for the bulk of Union's earnings, earnings generated from its unregulated storage business (approximately 12% of EBITDA in 2017) could expose the Company to some earnings volatility. DBRS views this segment as higher risk than the regulated distribution and storage business because of the impact of seasonality on storage demand and rates.

Continued on P.2

Financial Information

	9 mos. ended Sep. 30		12 mos. ended Sep. 30	12 mos. ended Dec. 31				
	2017	**2016**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**
Cash flow/debt	10.7%	11.9%	10.8%	11.3%	11.0%	13.4%	14.4%	14.0%
Lease-adjusted debt/capital	66.5%	66.3%	66.5%	67.1%	65.8%	65.8%	65.1%	64.2%
EBIT interest coverage (times)	2.26	2.38	2.17	2.24	2.27	2.43	2.48	2.35

Issuer Description

Union is a utility that provides natural gas distribution, transmission and storage services in Southwestern, Northern and Eastern Ontario, serving approximately 1.5 million customers. Union's common stock is held by Great Lakes Basin Energy L.P., a wholly owned limited partnership of Westcoast Energy Inc. (Westcoast; rated A (low), Stable by DBRS). Westcoast is indirectly owned by its ultimate parent, Enbridge.

Rating Update (CONTINUED)

Union's credit metrics have been pressured over the past few years because of high capex spending, primarily on transmission expansions. DBRS expects Union's capital spending program to be relatively high at approximately $1.0 billion in 2017 ($751 million spent for the nine months ended September 30, 2017 (9M 2017)). As major projects (including the 2017 Dawn-Parkway Expansion and the Panhandle Reinforcement Project) were placed in service in the second half of 2017 (H2 2017), capex for 2018 is expected to be lower. DBRS expects the incremental full-year cash flow from projects placed in service and the lower capex needs to result in a gradual improvement in credit metrics in 2018. In the medium term, the ratings could come under pressure should the Company fail to maintain its debt-to-capital ratio in line with the regulatory capital structure of 64% debt and 36% equity or should cash flow-to-debt remain below the "A" rating range on a sustained basis.

Rating Considerations

Strengths

1. Supportive regulatory environment
Union's gas-regulated distribution business operates under a supportive regulatory environment, which provides predictable cash flows and allows the Company to earn a reasonable return on its investments. The Company currently operates under a five-year IR framework (2014 to 2018), with rebasing under the COS framework in between IR periods. Union's regulated distribution business is not exposed to commodity price risk, as gas supply costs are adjusted quarterly and passed through to customers.

2. Large customer base and strong franchise
Union's cash flow is supported by a large customer base (1.5 million), which is growing at a steady rate, making Union one of the largest natural gas distributors in Canada. The Company provides transportation and storage services to almost all, and distribution to most, gas-fired generation plants in Ontario. Union's Dawn storage facility (163 billion cubic feet (bcf) capacity) acts as a gateway for Western Canadian and Appalachian gas supply and is strategically connected to key pipelines transporting natural gas to major Canadian and U.S. markets. Long-term demand for natural gas in Ontario is expected to remain relatively stable with continued growth in peak daily demand. Union's transmission system has an effective peak daily demand capacity of 7.2 bcf. Moreover, the Company's franchise area covers more than 400 communities in Northern, Southwestern and Eastern Ontario. Approximately 60% of Union's revenue is generated from residential and commercial customers, a segment that is less exposed to economic downturns.

3. Growing rate base
Union's regulated rate base has grown in the past few years with the addition of major transmission and expansion of storage assets to reach over $5.5 billion in 2017 ($4.8 billion in 2016). The growing rate base is expected to benefit earnings and cash flow for the Company going forward.

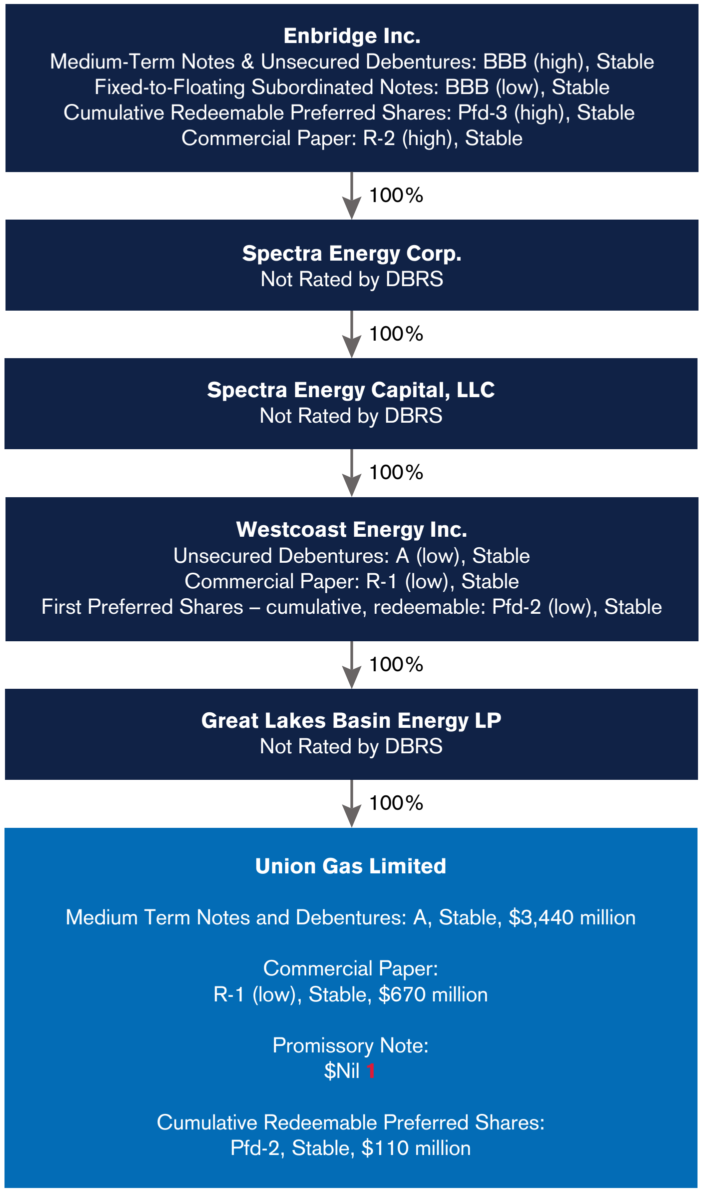
Challenges

1. Consistent free cash flow deficits
Union has generated free cash flow deficits because of higher capex primarily for transmission expansions. This is expected to moderate in the next two years as several projects have been completed and placed in service. In the interim, DBRS expects the Company to finance the deficits prudently by managing debt levels, dividend payouts and infusion of equity in order to maintain an improved cash flow coverage and keep its debt-to-capital ratio within regulatory levels.

2. Seasonality and volume risk
The natural gas distribution business is subject to seasonality related to volume-based rates and the significant effect of the winter heating season on volumes. Union is exposed to a degree of demand risk since its rates are based on forecast volumes, which are sensitive to changes in weather. Natural gas rates approved by the OEB assume normal weather conditions. Since a majority of the gas distributed by Union to the residential and commercial markets is used for space heating and is charged using volume-based rates, differences from normal weather could have a significant effect on the consumption of gas and on the Company's financial results. However, DBRS notes that under the IR framework, Union is allowed to recover shortfalls relative to normalized consumption on an annual basis with a one-year lag. The Company has also increased fixed monthly charges for residential and small commercial customers to partially mitigate the impact of volume changes.

3. Earnings volatility of non-regulated storage
Union's non-regulated storage earnings add some volatility in earnings. DBRS views this segment as higher risk than the regulated distribution and storage business because of the impact of seasonality on storage demand and rates. In 2017, Union's non-regulated storage business accounted for approximately 12% of EBITDA.

Simplified Organizational Chart (as at September 30, 2017)



1 The Company has a promissory note to borrow up to $150 million from Great Lakes Basin Energy L.P. on an unsecured basis.

Earnings and Outlook

	9 mos. ended Sep. 30		12 mos. ended Sep. 30	12 mos. ended Dec. 31				
($ millions, where applicable)	**2017**	**2016**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**
Gas distribution margin	599	585	826	812	800	778	772	727
Storage and transportation revenues	246	206	318	278	239	266	252	269
Ancillary revenue	13	12	22	21	26	21	26	28
Operating revenue	858	803	1,166	1,111	1,065	1,065	1,050	1,024
Operating expenses	(371)	(339)	(516)	(484)	(468)	(465)	(464)	(445)
EBITDA	487	464	650	627	597	600	586	579
Depreciation and amortization	(200)	(181)	(258)	(239)	(224)	(212)	(204)	(213)
EBIT	287	283	392	388	373	388	382	366
Gross interest expense	(127)	(119)	(181)	(173)	(164)	(160)	(154)	(156)
Earning before taxes	160	164	223	227	216	232	228	210
Core net income	155	152	209	206	188	196	191	170
Reported net income	155	152	208	205	188	195	207	170
Return on common equity	11.4%	12.6%	11.6%	12.7%	13.0%	14.6%	15.5%	14.8%
Distribution rate base 1	n/a	n/a	n/a	4,758	4,228	3,976	3,784	3,570

1 n/a: not available on a quarterly basis.

Summary

- Approximately 88% of Union's EBITDA is generated from its regulated gas distribution, storage and transmission businesses. The balance is generated from the Company's unregulated storage business, which carries some earnings volatility resulting from seasonal fluctuation in demand and rates.
- The Company's EBITDA increased in 2016 primarily as a result of an increase in transportation revenue from the 2015 Dawn-Parkway Expansion project and higher storage pricing.
- For 9M 2017, the Company's EBITDA was marginally higher as it benefitted from additional revenue from the 2016 Dawn-Parkway Expansion and Burlington-Oakville pipeline projects. Earnings before interest and taxes (EBIT) remained relatively unchanged as the increase in operating revenue was largely offset by an increase in depreciation expense from projects placed into service.

Outlook 2018

- DBRS anticipates that Union's earnings will likely improve modestly in the near term as a result of customer growth and higher storage and transportation revenue from major capital projects placed in service H2 2017.
- Barring the impact of unpredictable weather conditions, DBRS expects ongoing energy conservation programs, including the Company's Demand Side Management Initiative, to have a modest impact on customer usage. However, any impact on earnings is mitigated through the regulatory framework. Furthermore, the Company expects modest annual customer growth of approximately 1% to 2%.

Financial Profile

	9 mos. ended Sep. 30		12 mos. ended Sep. 30	12 mos. ended Dec. 31				
($ millions, where applicable)	2017	2016	2017	2016	2015	2014	2013	2012
Core net income	155	152	209	206	188	196	191	170
Depreciation & amortization	200	181	258	239	224	212	204	213
Deferred income taxes and other	(17)	4	(13)	8	(40)	13	19	(8)
Cash Flow (Bef. Working Cap. Changes)	**338**	**337**	**454**	**453**	**372**	**421**	**414**	**375**
Dividends paid	(2)	(2)	(3)	(3)	(53)	(103)	(152)	(165)
Capital expenditures	(751)	(756)	(1,031)	(1,036)	(701)	(474)	(370)	(271)
Free Cash Flow (Bef. W/C Changes)	**(415)**	**(421)**	**(580)**	**(586)**	**(382)**	**(156)**	**(108)**	**(61)**
Changes in non-cash work. cap. items	203	45	107	(51)	129	(116)	(94)	58
Net Free Cash Flow	**(212)**	**(376)**	**(473)**	**(637)**	**(253)**	**(272)**	**(202)**	**(3)**
Acquisitions & long-term investments	0	0	0	0	0	0	0	0
Short-term investments	0	0	0	0	0	0	0	0
Proceeds on asset sales	0	0	0	0	0	0	0	0
Net equity change	30	0	30	0	0	0	0	0
Net debt change	186	386	422	622	240	282	203	5
Other	0	0	37	37	(2)	0	0	0
Change in Cash	**4**	**10**	**16**	**22**	**(15)**	**10**	**1**	**2**
Total debt	4,193	3,770	4,193	4,006	3,384	3,144	2,873	2,670
Cash and equivalents	31	15	31	27	5	20	10	9
Lease-adjusted debt/capital	66.5%	66.3%	66.5%	67.1%	65.8%	65.8%	65.1%	64.2%
Cash flow/debt	10.7%	11.9%	10.8%	11.3%	11.0%	13.4%	14.4%	14.0%
EBIT interest coverage (times)	2.26	2.38	2.17	2.24	2.27	2.43	2.48	2.35
Total dividend payout ratio	1.3%	1.3%	1.4%	1.5%	28.2%	52.6%	79.6%	97.1%

Summary

- Operating cash flow was higher in year-end (YE) 2016 relative to YE2015, as a result of stronger earnings and lower tax installments. Operating cash flow remained stable in 9M 2017, relative to 9M 2016.
- The Company's capex has been relatively high over the last two years as a result of spending on transmission expansion projects, including:
  - The 2016 Dawn-Parkway Expansion project ($363 million; in service Q4 2016).
  - Burlington-Oakville pipeline project ($85 million; in service Q4 2016).
  - 2017 Dawn-Parkway Expansion project ($620 million; in service Q3 2017).
  - Panhandle Reinforcement Project ($243 million; in service Q4 2017).
- The elevated capex program has resulted in Union generating free cash flow deficits that have been largely funded by additional debt. Consequently, the Company's key credit metrics continue to be pressured. However, DBRS expects the pressure to abate in 2018, as the Company realizes the full impact of the incremental cash flow from projects placed in service in 2017.
- Union has a flexible dividend policy. Dividends are primarily used to maintain Union's capital structure in line with regulatory-approved levels (64% debt and 36% equity).

Outlook 2018

- DBRS expects Union's full-year capex for 2017 to be comparable with 2016 capex spending.
- DBRS expects overall capex to trend lower in 2018 as a result of lower spending on expansion projects.
- DBRS expects the Company to maintain its leverage in line with the OEB-approved capital structure by prudently managing debt levels, dividend payouts and infusion of equity.

Liquidity and Long-Term Debt Maturities

Credit Facility

(As at Sep. 30, 2017; $ millions)	Maturity Date	Committed	CP	Available
Multi-year syndicated	2021	700	670	30

- The Company's credit facility is mainly used to backstop its $700 million commercial paper program that supports Union's working capital needs.
- DBRS views the Company's liquidity as adequate to support its working capital funding requirements.
- Union is generally subject to seasonality as a part of its business and, as a result, its short-term debt and its gas inventory typically peak in the first and fourth quarters of every year.
- The facility contains a maximum 75% debt-to-capital covenant and includes a provision requiring the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. As at September 30, 2017, the Company was in compliance with the covenants.

Debt Maturity Schedule

(As at Sep. 30, 2017; $ millions)	2018	2019	2020	2021	Thereafter	Total
MTNs and Debentures	400	0	0	200	2,840	3,440

- Union's debt maturity is well spread out and manageable. DBRS expects the refinancing risk to be minimal, given the Company's good access to debt capital markets.
- In November 2017, the Company issued $250 million 2.88% medium term note debentures (unsecured), due November 2027, and $250 million 3.59% medium term note debentures (unsecured), due November 2047.
- Under the terms of the trust indentures relating to certain debentures, Union has agreed to several covenants. Therefore, the Company can have a maximum total debt-to-capitalization of 75%, and any incremental debt is subject to a minimum interest coverage test of 2.0 times (x). As at September 30, 2017, the Company was in compliance with all covenants.

Regulation

Regulatory Overview

- Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB (refer to the section titled "Assessment of Union's Regulatory Environment"). The regulatory environment in Ontario for natural gas distributors is viewed as supportive.

Gas Distribution

- Union's distribution rates are set under a multi-year IR framework, with rebasing under the COS framework occurring between the IR periods.
- From 2014 to 2018, Union will be regulated under the IR framework. Under this framework, the Company will be able to increase rates annually by an inflation factor, which will be offset by a productivity factor of 60%; thus, the annual net rate escalator in each year is 40% of inflation.
- For 2014 to 2018, the Company has an approved ROE of 8.93% and a deemed equity component of 36%. The earnings-sharing mechanism permits Union to fully retain the ROE from regulated operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.
- The Company is allowed to pass through to its customers gas commodity and upstream transportation costs on a quarterly basis and demand side management costs on annual basis. It is also allowed additional pass-through of costs associated with major capital investments and certain fuel variances, an allowance for unexpected cost changes that are outside of management's control, equal sharing of taxes between customers and an earnings-sharing mechanism.
- In September 2017, the Company filed an application with the OEB for new rates effective January 1, 2018, pursuant to an IR framework. The application as approved in January 2018 with the impact on a typical residential customer varying from $9 to $14 per annum, depending on the customer's location.
- The Company is also allowed to recover costs related to the implementation and operation of the Province of Ontario's of Cap and Trade program from its customers. As part of its compliance plan, the Company files a separate application with the OEB to recover the costs associated with the Cap and Trade program.
- On November 2, 2017, Union and EGD filed an application with the OEB to amalgamate. Enbridge expects that the regulatory review will take the better part of 2018. Enbridge's final decision on the amalgamation is dependent on OEB's approval and Enbridge's assessment of the regulatory outcomes.

Gas Storage

- Storage services outside Union's franchise area or new storage services to customers in the franchise area are not regulated by the OEB. This accounts for approximately one-third of storage capacity.
- Storage within Union's service area is regulated under the COS regulation.

Assessment of Union's Regulatory Environment

Criteria	Score	Analysis
Deemed Equity Ratio	Excellent Good Satisfactory **Below Average** Poor	The OEB allows Union to have a deemed equity of 36%, which is consistent with the other gas distributors in Ontario. However, deemed equity is below peer utilities in Canada and the United States.
Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	For 2014 to 2018, the Company has an approved ROE of 8.93%. In addition, the earnings-sharing mechanism permits Union to fully retain the ROE from regulated operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers and share 90% of any earnings above 10.93% with customers.
Energy Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	The Company is able to fully pass through gas commodity and upstream transportation costs on a quarterly basis and demand side management costs on an annual basis. It is also allowed additional pass-through of costs associated with major capital investments and certain fuel variances, an allowance for unexpected cost changes that are outside of management's control, equal sharing of taxes between customers and an earnings-sharing mechanism.
Capital and Operating Cost Recoveries	Excellent **Good** Satisfactory Below Average Poor	Major capital costs are pre-approved by the regulator and added to the rate base after completion. Other capital spending after the base year will not be approved until the next rate application and approval of the rate base.
COS vs. IRM	Excellent Good **Satisfactory** Below Average Poor	Union's distribution rates are set under a five-year IR framework, with rebasing under the COS framework between the IR periods. Under this framework, Union will be able to increase rates annually by an inflation factor, which will be offset by a productivity factor of 60% of inflation; thus, the annual net rate escalator in each year is 40% of inflation.
Political Interference	Excellent **Good** Satisfactory Below Average Poor	There is low degree of government influence. Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB.
Stranded Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	Union has very limited history of stranded costs.
Rate Freeze	**Excellent** Good Satisfactory Below Average Poor	Rates are based on the market price of natural gas plus distribution and servicing costs. Rates have not been frozen within the past decade.

Union Gas Limited

Balance Sheet ($ millions)	Sep. 30	Dec. 31				Sep. 30	Dec. 31		
Assets	2017	2016	2015	2014	Liabilities & Equity	2017	2016	2015	2014
Cash & equivalents	31	27	5	20	S.T. borrowings	772	586	263	318
Accounts receivable	516	816	648	1,135	Accounts payable	656	878	793	1,117
Inventories	254	245	299	239	Current portion L.T.D.	450	125	200	150
Income tax receivables & other	64	29	24	17	Deferred taxes & other	0	0	0	25
Total Current Assets	**865**	**1,117**	**976**	**1,411**	**Total Current Liab.**	**1,878**	**1,589**	**1,256**	**1,610**
Net fixed assets	7,086	6,508	5,678	5,154	Long-term debt	2,971	3,295	2,921	2,676
Regulatory assets & others	638	602	536	469	Asset retirement obligations	431	417	440	368
					Deferred income taxes	550	516	451	417
					Regulatory liabilities & others	760	602	509	497
					Minority interest	0	0	0	8
					Preferred shares	110	110	110	110
					Common equity	1,889	1,698	1,503	1,348
Total Assets	**8,589**	**8,227**	**7,190**	**7,034**	**Total Liab. & SE**	**8,589**	**8,227**	**7,190**	**7,034**

Balance Sheet and Liquidity Capital Ratios

	9 mos. ended Sep. 30		12 mos. ended Sep. 30	12 mos. ended Dec. 31				
	2017	2016	2017	2016	2015	2014	2013	2012
Current ratio (times)	0.46	0.80	0.46	0.70	0.78	0.88	0.77	0.74
Debt/capital	66.1%	66.1%	66.1%	66.8%	65.4%	65.5%	64.7%	63.9%
Lease-adjusted debt/capital	66.5%	66.3%	66.5%	67.1%	65.8%	65.8%	65.1%	64.2%
Cash flow/debt	10.7%	11.9%	10.8%	11.3%	11.0%	13.4%	14.4%	14.0%
Lease-adjusted cash flow/debt	10.6%	11.9%	10.7%	11.3%	10.9%	13.3%	14.3%	13.9%
(Cash flow – dividends)/capex (times)	0.45	0.44	0.44	0.43	0.46	0.67	0.71	0.77
Total dividend payout ratio	1.3%	1.3%	1.4%	1.5%	28.2%	52.6%	79.6%	97.1%
Coverage Ratios (times)								
EBIT interest coverage	2.26	2.38	2.17	2.24	2.27	2.43	2.48	2.35
EBITDA interest coverage	3.83	3.90	3.59	3.62	3.64	3.75	3.81	3.71
Fixed-charge coverage	2.20	2.31	2.10	2.18	2.20	2.35	2.40	2.27
Lease-adjusted EBIT interest coverage	2.24	2.36	2.15	2.23	2.26	2.41	2.46	2.33
Profitability Ratios								
EBITDA margin	56.8%	57.8%	55.7%	56.4%	56.1%	56.3%	55.8%	56.5%
EBIT margin	33.4%	35.2%	33.6%	34.9%	35.0%	36.4%	36.4%	35.7%
Profit margin	18.1%	18.9%	17.9%	18.5%	17.7%	18.4%	18.2%	16.6%
Return on common equity	11.4%	12.6%	11.6%	12.7%	13.0%	14.6%	15.5%	13.6%
Return on capital	4.5%	5.1%	4.7%	5.1%	5.5%	6.1%	6.5%	6.4%

Rating History

	Current	2017	2016	2015	2014	2013	2012
Issuer Rating	A	A	A	A	A	A	A
Unsecured Debentures/Medium-Term Note	A	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cumulative Redeemable Preferred Shares	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Previous Action

- Confirmed, February 9, 2017.

Commercial Paper Limit

- $700 million.

Previous Report

- Union Gas Limited: Rating Report, February 16, 2017.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

The DBRS group of companies consists of DBRS, Inc. (Delaware, U.S.)(NRSRO, DRO affiliate); DBRS Limited (Ontario, Canada)(DRO, NRSRO affiliate); DBRS Ratings Limited (England and Wales) (CRA, NRSRO affiliate, DRO affiliate); and DBRS Ratings México, Institución Calificadora de Valores S.A. de C.V. (Mexico)(CRA, NRSRO affiliate, DRO affiliate). Please note that DBRS Ratings Limited was registered as an NRSRO affiliate on July 14, 2017. For more information on regulatory registrations, recognitions and approvals, please see: http://www.dbrs.com/research/225752/highlights.pdf.

STANDARD & POOR'S RATINGS SERVICES

Research

Summary:
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Primary Credit Analyst:
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Summary:

Enbridge Gas Distribution Inc.

Credit Rating:	A-/Stable/--

Rationale

The ratings on Toronto-based Enbridge Gas Distribution Inc. (EGD) reflect Standard & Poor's Ratings Services' view of the company's excellent business risk profile and significant financial risk profile. In our opinion, supporting the excellent business risk profile are Enbridge Gas' low-risk, regulated cash flow; position as a monopoly gas network business; and lack of direct commodity price risk. The company has exposure to weather-induced variability in gas demand and cash flow and relatively high stand-alone leverage, which we believe offset these strengths.

EGD is a regulated natural gas distribution business that serves primarily eastern Ontario, including the Toronto region and Ottawa. It is an indirectly held, wholly owned subsidiary of Enbridge Inc. (A-/Stable/--). The company had about C$3.1 billion in debt as of Sept. 30, 2012.

The corporate credit rating on Enbridge Gas reflects our stand-alone evaluation of the company; at the current level, the ratings on ultimate parent, Enbridge, do not constrain the ratings on EGD. However, a material intercorporate lending arrangement between the parent and subsidiary links the credit profiles of the two. Accordingly, any decline in the rating on the parent would likely result in a similar decline in the rating on Enbridge Gas.

The company's low risk regulated cash flow supports its excellent business risk profile, in our opinion. Consistent and predictable regulatory decisions from its regulator, the Ontario Energy Board (OEB), support our view. Underpinning stable cash flows are rates that are reset based on cost of service methodology between periods of incentive regulation that last five years. During incentive periods, revenues and related rates are affected primarily by inflation and a regulator-established productivity factor. EGD does not face any commodity price risk because it passes the cost of gas to customers through an established quarterly adjustment mechanism.

We believe Enbridge Gas' natural monopoly and favorable markets support its competitive position. The company has limited bypass risk, and competition faces competition from oil and electricity. It continues to experience growth in customer numbers among its residential, commercial, and industrial customers.

EGD continues to be somewhat exposed to weather-induced variability in gas demand and related cash flows. Under the current regulatory framework, revenue shortfalls can result from lower-than-forecast volumes (typically from a warmer-than-expected winter). This shortfall can lead to somewhat greater volatility in earnings compared with those of other regulated utilities in Canada. Weather volatility led to an approximately 5% decline in funds from operations (FFO) through the first nine months of 2012.

Credit metrics for the stand-alone rating are relatively weak, in our view, with adjusted FFO (AFFO)-to-debt of 14.6% in the past 12 months. The company maintained relatively stable credit metrics from 2008-2011, which covered the first four years of the current incentive regulation period. AFFO-to-debt averaged about 17%.

Liquidity

We believe EGD has adequate liquidity as per our criteria. Our assessment incorporates the following expectations and assumptions:

- We expect the company's sources over uses to exceed 1.2x during the next 12 months, even in the unlikely event that EBITDA declines by 15%.
- Enbridge Gas will continue to have solid relationships with its banks, a generally high standing in credit markets, and very prudent risk management.
- We expect sources of liquidity in the next 12 months to include FFO of about C$500 million, and revolver availability of about C$132 million and low levels of cash on hand as of Sept. 30, 2012.
- Uses of funds are forecast to include capital spending of about C$500 million and reduced dividends, net of reinvestment to finance growth.
- We also expect parental support if required, provided the parent had economic incentive to do so.

We expect the company to continue complying with all of its covenants.

Outlook

The stable outlook reflects our expectations of EGD's continued sound operations and a fair regulatory environment. Given the intercorporate transaction links in the ratings to the parent, a positive outlook or upgrade during our two-year outlook horizon is unlikely unless Enbridge's credit profile also improves. A negative outlook or downgrade could occur if we were to lower the rating on the parent.

Related Criteria And Research

- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Key Credit Factors: Criteria For Rating The Global Midstream Energy Industry, April 18, 2012
- Criteria Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent, March 11, 2010
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- 2008 Corporate Criteria: Ratios And Adjustments, April 15, 2008
- 2008 Corporate Criteria: Commercial Paper, April 15, 2008

STANDARD & POOR'S RATINGS SERVICES

Research

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Summary:
Enbridge Gas Distribution Inc.

Corporate Credit Rating	A-/Stable/--
Profile Assessments	
BUSINESS RISK	EXCELLENT
FINANCIAL RISK	SIGNIFICANT

Vulnerable — Excellent

Highly leveraged — Minimal

Rationale

Business Risk: Excellent	Financial Risk: Significant
• Highly stable cash flows supported by regulated natural gas distribution, with commodity cost flow through • Exposure to variations in weather, which can reduce gas consumption and revenues	• Financial metrics that we believe will be relatively weak for the next two years

Outlook: Stable

The stable outlook reflects Standard & Poor's Ratings Services' expectations of Enbridge Gas Distribution Inc.'s (EGD) continued sound operations and a fair regulatory environment. We have equalized the ratings on EGD with those on parent Enbridge Inc.

Downside scenario

A negative outlook or downgrade could occur if we were to lower the rating on the parent.

Upside scenario

Given the intercorporate transaction links in the ratings to the parent, a positive outlook or upgrade during our two-year outlook horizon is unlikely unless Enbridge's credit profile also improves.

Standard & Poor's Base-Case Scenario

Our base-case assumptions include moderate volume growth in its jurisdiction and no major changes to its customer mix. We expect the regulatory environment to remain stable.

Assumptions

- Volume growth of approximately 2%
- Cost-of-service regulation in 2013, with a return to incentive-based mechanisms in 2014
- Funds from operations (FFO) of approximately C$400 million
- Maintenance of the regulated 64%-36% capital structure

Key Metrics

	2012A	2013E	2014E
AFFO/debt	17.7%	13%-14%	13-14%
Debt/EBITDA	4.3x	5.0x-5.5x	5.0x-5.5x
FFO interest coverage	4.3x	2.7x-3.2x	2.7x-3.2x

AFFO--Adjusted funds from operations. FFO--Funds from operations. A--Actual. E--Estimate.

Business Risk: Excellent

The "excellent" business risk profile reflects our view of the highly stable regulated cash flows from natural gas distribution in its jurisdiction. EGD expects to spend significant capex in coming years to replace and expand infrastructure –- we expect that the regulator will preapprove this. The company is operating under a cost-of-service methodology in 2013, and will transition back to incentive regulation in 2014. We expect no changes to the regulatory environment, and that EGD will continue to earn its allowed return on equity.

Financial Risk: Significant

We view the financial risk profile as "significant". EGD has a high degree of allowed leverage for regulatory purposes, and the regulated capital structure allows for more leverage than similar electrical local distribution companies. We expect to see stable financial metrics in the 13%-14% AFFO-to-debt range in the coming two years, with no change to the capital structure.

Liquidity: Adequate

We view Enbridge Gas' liquidity as "adequate" under our criteria for the next 12 months, with sources less uses being positive, and sources minus uses being greater than 1.2x.

Principal Liquidity Sources

- Committed credit facility availability of C$130 million
- Debt and share issuance of about C$650 million
- FFO of C$300 million-C$315 million

Principal Liquidity Uses

- Dividends to the parent of C$220 million
- Capex of C$650 million-C$680 million

Related Criteria And Research

- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Key Credit Factors: Criteria For Rating The Global Midstream Energy Industry, April 18, 2012
- Criteria Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent, March 11, 2010
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008
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- 2008 Corporate Criteria: Commercial Paper, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk					
Business Risk	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA/AA+	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	B- or below

Note: These rating outcomes are shown for guidance purposes only. The ratings indicated in each cell of the matrix are the midpoints of the likely rating possibilities. There can be small positives and negatives that would lead to an outcome of one notch higher or lower than the typical matrix outcome. Moreover, there will be exceptions that go beyond a one-notch divergence. For example, the matrix does not address the lowest rungs of the credit spectrum (i.e., the 'CCC' category and lower). Other rating outcomes that are more than one notch off the matrix may occur for companies that have liquidity that we judge as "less than adequate" or "weak" under our criteria, or companies with "satisfactory" or better business risk profiles that have extreme debt burdens due to leveraged buyouts or other reasons. For government-related entities (GREs), the indicated rating would apply to the standalone credit profile, before giving any credit for potential government support.

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

Research

Summary:
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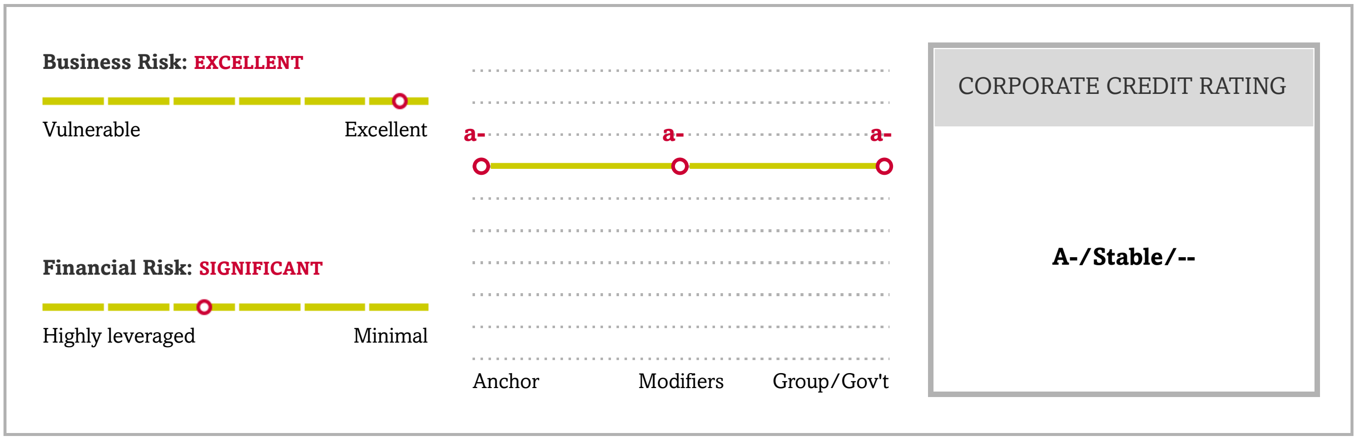
Summary:

Enbridge Gas Distribution Inc.



Rationale

Business Risk: Excellent	Financial Risk: Significant
• Diversified asset base primarily in low-volatility liquids pipelines and regulated natural gas distribution, with smaller contribution from sponsored investments, gas pipelines, and other services • Lack of direct commodity exposure for those segments, with market fundamentals and long-term contracts driving stable volumes	• Weak financial metrics for Standard & Poor's Ratings Services' two-year forecast period • Expected very high capital expenditures in the next several years, which will pressure financial metrics and require significant external financing

Outlook: Stable

The stable outlook on Enbridge Gas Distribution Inc. reflects that on Enbridge Inc. The stable outlook reflects our view that Enbridge's cash flow from both the existing businesses and new developments will remain very stable. We believe credit metrics, although weak for the ratings, will remain above established thresholds.

Downside scenario

A lowering of adjusted funds from operations (AFFO)-to-debt below 13% would likely result in a downgrade. Deterioration in the business risk or a failure to deliver the capital program on time and budget could also result in a lower rating.

Upside scenario

An upgrade during our two-year outlook horizon is unlikely without a material amount of deleveraging such that AFFO-to-debt improves above 20%.

Standard & Poor's Base-Case Scenario

Assumptions

- Volume flows on the mainline will remain stable
- The large capital program will exceed C$8 billion, funded through hybrids, drop-downs, debt, and equity
- Dividend growth will remain stable at about 7%
- No regulatory or permitting delays at major projects that would impair in service dates

Key Metrics

	2013A	2014E	2015E
EBITDA Margin	14.7%	15%-17%	19%-21%
AFFO/debt	12.2%	11%-13%	12%–14%
Debt/EBITDA	6.0x	6.0x–7.0x	5.5x–6.5x

AFFO--Adjusted funds from operations. A--Actual. E--Estimate.

Business Risk: Excellent

We view Enbridge's business risk as "excellent," with an "excellent" competitive position. The company generates a significant portion of its cash flow through tolls on the liquids pipelines and earnings from regulated gas distribution. Although the competitive tolling settlement expose Enbridge to a higher degree of volume risk, the fundamentals of increasing Alberta crude oil production and constrained export capacity bode well for seeing volumes remain strong. The company does not take direct commodity risk on the pipelines, and the contract profile is long-term with generally creditworthy counterparties. We expect new projects to feature long-term contracts that limit volume risk, with no commodity exposure that generate stable cash flows.

Gas distribution accounts for approximately 15% of cash flow, and we believe consistent and predictable regulation, commodity cost pass-through, and a demonstrated ability to earn the allowed return on equity established by the regulator support the excellent competitive position.

Financial Risk: Significant

We view Enbridge's financial risk profile as "significant". A very large capital program to expand existing and build new liquids pipelines will pressure financial metrics for the next several years. We expect that there will be very limited headroom above our 13% AFFO-to-debt downgrade threshold, and that financial policy, including the mix of external financing and dividend growth, will be crucial to maintaining the rating.

Liquidity: Adequate

We view Enbridge Inc.'s liquidity as "adequate." Sources less uses is positive, and sources over uses is greater than 1.2x. We believe the company will continue to have solid relationships with its banks, a generally high standing in credit markets, and generally prudent risk management.

Principal Liquidity Sources	Principal Liquidity Uses
• Expected FFO of C$4.4 billion-C$4.6 billion • Committed credit facilities availability of C$12.0 billion–C$12.5 billion • Equity and hybrid issuances of C$2.8 billion–C$2.9 billion	• Capital expenditures of C$8.7 billion–C$8.9 billion • Dividends of C$1.3 billion–C$1.5 billion

Other Modifiers

The modifying factors had no effect on the ratings.

Group Influence

We view Enbridge Pipelines Inc. and Enbridge Gas Distribution as "core" to parent Enbridge Inc. Our assessment equalizes the ratings on them with that on the parent.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** a-
- **Entity status within group:** Core (no impact)

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Jan. 2, 2014
- Key Credit Factors For The Midstream Energy Industry, Dec. 19, 2013
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

Research

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Summary:

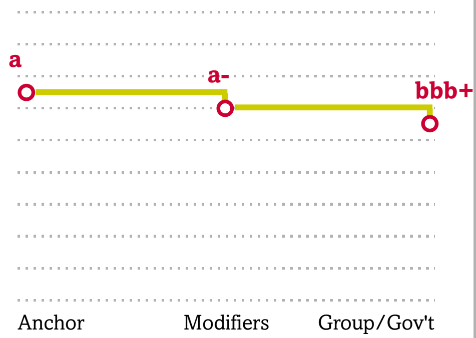
Enbridge Gas Distribution Inc.

Business Risk: **EXCELLENT**

Vulnerable — Excellent

Financial Risk: **INTERMEDIATE**

Highly leveraged — Minimal



CORPORATE CREDIT RATING

BBB+/Stable/--

Rationale

Business Risk: Excellent	Financial Risk: Intermediate
• A relatively transparent and predictable regulatory regime • Commodity costs that are passed through • The ability to recover all prudently incurred fixed and variable operating costs • Diverse and relatively stable customer base	• Stable regulated cash flow • Credit metrics at low end of financial risk profile

Outlook: Stable

The stable outlook on Enbridge Gas Distribution Inc. (EGD) reflects the consolidated outlook on its parent group Enbridge Inc. (Enbridge) because Standard & Poor's Ratings Services' views EGD to be "core" to the Enbridge group under its group rating methodology.

The stable outlook on Enbridge reflects our assessment of the underlying operational and financial stability of the operating companies. We expect these operating subsidiaries, including EGD, to continue generating stable and predictable cash flow during our outlook period. We believe credit metrics, although weak for the ratings, will remain above established thresholds.

Downside scenario

Although unlikely, we could lower the 'a-' SACP on EGD should there be a material negative change in our assessment of the regulatory framework in Ontario, major cost overruns in its capital programs or an adverse regulatory decision that results in our expectation of adjusted funds from operations (AFFO)-to-debt to fall and stay below 11%. However, because we deem the subsidiary to be "core" to Enbridge this will not impact our 'BBB+' final rating on EGD unless the group credit profile (GCP) of 'bbb+' were also to deteriorate. Given EGD's relative size in the group, and all else being equal, we would not expect a decline in its performance and stand-alone credit profile (SACP) alone to negatively affect the GCP.

We expect EGD will continue generating stable cash flow under custom Incentive rate-setting method in 2015 and 2016 as it continues to execute its capital expenditure plan. We therefore expect that its SACP will be unchanged at 'a-' during our two-year outlook horizon.

Upside scenario

We could raise EGD's SACP by removing the "negative" comparable ratings analysis (CRA) if the company decides to adopt a more conservative leverage target improving its AFFO-to-debt to above 18% permanently, although we consider this unlikely during our outlook horizon. Nevertheless, under those circumstances, the ratings on EGD would remain the same as those on Enbridge, capped by the GCP of 'bbb+', unless the GCP at the parent level also improved, which we do not expect during our outlook period. In addition, we do not expect an improvement in EGD's SACP alone to drive an increase to the parent's GCP given their relative sizes.

Standard & Poor's Base-Case Scenario

EGD is Canada's largest natural gas distribution utility operator. The company operates more than 37,600 kilometers of gas distribution pipelines throughout the province of Ontario. EGD is a wholly owned subsidiary of Enbridge. The ratings' key driver continues to be the Ontario Energy Board's (OEB) regulatory framework and the utility's performance within it.

Assumptions

- EGD will continue to focus on its regulated natural gas distribution operations and remains contained in its unregulated activities
- It will not experience any adverse and material regulatory decisions and that the regulatory regime will remain transparent and stable
- The company will earn close to its allowed return on equity of 9.30% in 2015 and 9.19% in 2016 on its deemed capital structure
- Customer growth will be about 35,000 customers per year
- Gas distribution rates for 2014-2018 will be set under OEB's relatively new custom incentive rate-making (CIR)
- Dividend payout to parent will remain at 100% of earnings

Key Metrics

	2014A	2015E	2016E
AFFO/debt	12.4	12%-14%	13%-15%
Debt/EBITDA	6.4x	5.5x-6.5x	4.5x-5.5x

AFFO--Adjusted funds from operations. A--Actual. E--Estimated.

Business Risk: Excellent

EGD's "excellent" business risk profile reflects our assessment of the OEB regulatory framework that underpins the company's predictable and steady cash flow. In our view, the regulatory process is transparent, consistent, and predictable. Supporting consistency and predictability are the use of standard methodology applied to all utilities in its jurisdiction, including a transparent formula for allowed returns, and a consistent deemed capital structure that has not changed for many years. In addition, during times of change, the regulator follows a public process of study and consultation that allows management to adjust to new regulatory or market developments.

Gas distribution rates are typically determined in a timely fashion and allow for the recovery of prudently incurred operating and capital costs and the opportunity to earn a modest return. Furthermore, several mechanisms support timely recovery of material and unexpected capital costs, including rate riders and (in some circumstances) the ability to request a rate-reset hearing.

Under the Ontario regulatory regime, natural gas distributors, including EGD, have an obligation to ensure adequate supply of natural gas which increases operational risk; however the company has been able to mitigate this with diverse sources supply of natural gas. The completion of the Greater Toronto Area (GTA) project will diversify EGD's sources of natural gas supply, including the Western Canada Sedimentary Basin (WCSB), Chicago, Dawn, and Niagara (Marcellus/Utica formations) as opposed to being primarily dependent on WCSB before the expansion. Furthermore commodity costs (natural gas) flow through rates, thereby limiting EGD's exposure to commodity risk and associated cash flow volatility.

Our view of the business risk assessment also reflects our expectation that the company's customer profile will be stable, with majority of the gas distribution revenues coming from residential customers, who are less sensitive to macroeconomic stresses and business cycles. However, demand for natural gas in the residential-based customer class can change due to weather-driven changes, plus the lack of weather normalization in the rate structure can result in cash flow volatility.

Financial Risk: Intermediate

Our assessment of EGD's financial risk is "intermediate". We base this on our forecast AFFO-to-debt metric of 12%-14%, at the low end of the "intermediate" financial risk category during our outlook horizon. We use the low-volatility table when assessing the utility's cash flows to reflect the stability and predictability of the cash flow stream and that majority of the company's cash flows and operations are at the low end of the utility risk spectrum in gas distribution. EGD has completed a cost-of-service (COS) application under the CIR framework in 2014. In our forecast, we included the recovery of the purchase gas variance account and expect additional capital spending associated with the GTA project to be recover in the next COS application in 2019 subject to prudency testing.

The "excellent" business risk and "intermediate" financial risk profiles produce a split anchor score of 'a+/a'. We choose the lower score to reflect the weaker business risk of the gas distribution operation in Ontario relative to other utility operators. In Ontario, gas distributors have an obligation to supply natural gas and tariff rates are not subject to weather normalization which other utility operators such as electricity distribution are not subject to.

Liquidity: Adequate

Our view on EGD's liquidity is "adequate." We expect that liquidity sources will be adequate to cover uses more than 1.1x in the next 12 months. We expect that in the event of a 10% EBITDA decline, the company's sources of funds would still exceed its uses. In our view, EGD has sound relationships with its banks and generally prudent financial risk management. In the event of an unexpected financial stress situation, we believe the utility would scale back on its capital expenditures and has the flexibility to suspend dividend payments to preserve the credit metrics.

Principal Liquidity Sources	Principal Liquidity Uses
• Cash FFO of about C$630 million in the next 12 months • Committed credit facilities availability of about C$470 million as of September 2015, maturing from 2017-2019	• Capital expenditure of about C$620 million over the next 12 months • Dividends of about C$225 million over the next 12 months

Other Modifiers

We assigned a "negative" CRA modifier to EGD to reflect the company's overall credit strength. EGD's AFFO-to-debt was about 12.5% in 2014. During the outlook period, we project AFFO-to-debt of 12%-14%, at the low end of the "intermediate" financial risk category, which warrants a "negative" CRA assessment.

Group Influence

We base our ratings of EGD on our SACP of the company, and our view that the subsidiary is "core" to the Enbridge group. We believe that EGD is unlikely to be sold, and that its operations in regulated gas distribution is integral to the overall group strategy of Enbridge, itself essentially a large diversified holding company with operations in transporting crude oil and natural gas gathering, transporting, treatment and processing operations. We believe that senior management has demonstrated a long-term commitment of support. The parent has a track record of providing equity and liquidity support to EGD as required. The subsidiary is successful at what it does, it has been operating for more than five years (so there is no startup risk), and we are not aware of any ongoing performance problems that could result in underperformance against the group management earnings targets. We believe the parent is well aware of the limited returns allowed for regulated utilities and has shown consistent support of the subsidiary during a period of major capital growth. Furthermore, the parent and subsidiary are closely linked and share the same brand.

However, in our view, there are insufficient insulating factors to achieve ratings separation between EGD and its parent, based on our criteria, so the final rating on the subsidiary is linked to that on Enbridge, resulting in a negative one-notch impact.

Ratings Score Snapshot

Corporate Credit Rating

BBB+/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Intermediate

- **Cash flow/Leverage:** Intermediate

Anchor: a

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)

- **Comparable rating analysis:** Negative (-1 notch)

Stand-alone credit profile : a-

- **Group credit profile:** bbb-
- **Entity status within group:** Core (-1 notch from SACP)

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

S&P Global
Ratings

Research

Summary:
Enbridge Gas Distribution Inc.

Primary Credit Analyst:
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Secondary Contact:
Stephen R Goltz, Toronto (416) 507-2592; stephen.goltz@spglobal.com

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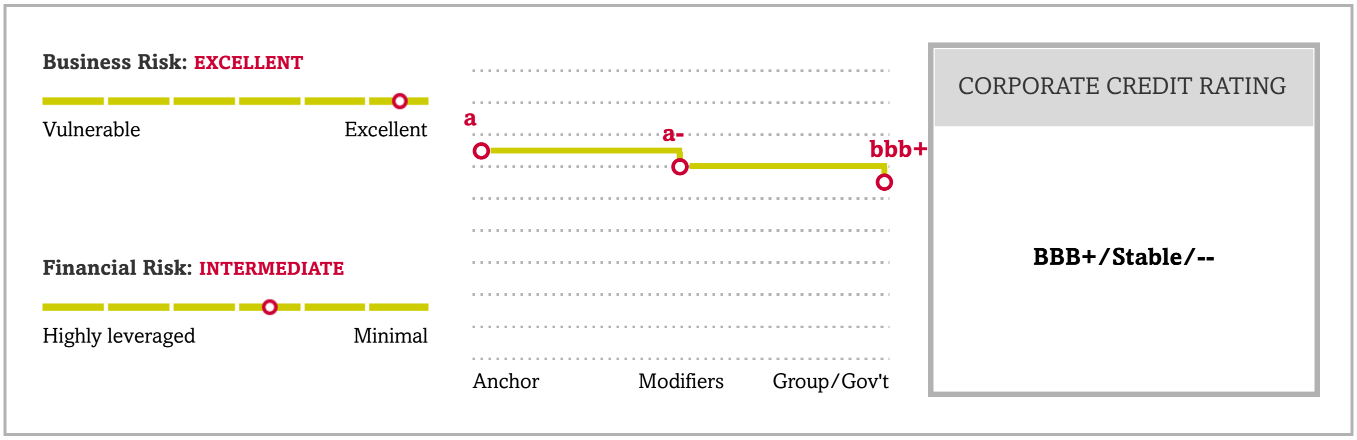
Summary:
Enbridge Gas Distribution Inc.



Rationale

Business Risk: Excellent	Financial Risk: Intermediate
• A relatively transparent and predictable regulatory regime • Commodity costs that are passed through • The ability to recover all prudently incurred fixed and variable operating costs • A coverage area that includes most of Ontario's largest cities, with a diverse and relatively stable customer base	• Stable regulated cash flow • Credit metrics at low end of financial risk profile

Outlook: Stable

The stable outlook on Enbridge Gas Distribution Inc. (EGD) reflects the consolidated outlook on its parent group Enbridge Inc. (Enbridge) because S&P Global Ratings views EGD to be core to the Enbridge group under its group rating methodology.

The stable outlook on Enbridge reflects our assessment of the underlying operational and financial stability of the operating companies. We expect these operating subsidiaries, including EGD, to continue generating stable and predictable cash flow during our outlook period. We believe credit metrics, although weak for the ratings, will remain above established thresholds.

Downside scenario

Although unlikely, we could lower the 'a-' SACP on EGD should there be a material negative change in our assessment of the regulatory framework in Ontario, major cost overruns in its capital programs or an adverse regulatory decision that results in our expectation of adjusted funds from operations (AFFO)-to debt to fall and stay below 11%. However, because we deem the subsidiary to be core to Enbridge this will not affect our 'BBB+' final rating on EGD unless the group credit profile (GCP) of 'bbb+' were also to deteriorate. Given the company's relative size in the group, and all else being equal, we would not expect a decline in its performance and stand-alone credit profile (SACP) alone to negatively affect the GCP.

We expect EGD will continue generating stable cash flow under custom incentive rate-making (CIR) mechanism in 2016 and 2017 as it continues to execute its capital expenditure plan. We therefore expect that the 'a-' SACP will not change during our two-year outlook horizon.

Upside scenario

We could raise EGD's SACP if the company decides to adopt a more conservative leverage target improving its sustained AFFO-to-debt to above 18%, although we consider this unlikely during our outlook horizon. Nevertheless, under those circumstances, the ratings on EGD would remain the same as those on Enbridge, capped by the GCP of 'bbb+', unless the GCP at the parent level also improved, which we do not expect during our outlook period. In addition, we do not expect an improvement in EGD's SACP alone to drive an increase to the parent's GCP given their relative sizes.

Our Base-Case Scenario

EGD is Canada's largest natural gas distribution utility operator. The company operates more than 37,600 kilometers of gas distribution pipelines throughout the province of Ontario. EGD is a wholly owned subsidiary of Enbridge. The ratings' key driver continues to be the relationship between EGD and its parent. The key driver of EGD's SACP continues to be the Ontario Energy Board's (OEB) regulatory framework and the utility's performance within it.

Assumptions

- EGD will continue to focus on its regulated natural gas distribution operations and remains contained in its unregulated activities
- It will not experience any adverse and material regulatory decisions and that the regulatory regime will remain transparent and stable
- The company will earn close to its allowed return on equity of 9.19% in 2016 and 8.78% in 2017 on its deemed capital structure
- The utility will gain about 30,000 customers per year
- Gas distribution rates for 2017 and 2018 will be set under OEB's CIR framework
- Dividend payout to parent will remain at 100% of earnings
- Enbridge would provide timely equity injection to EGD
- The cap and trade carbon tax will be a pass-through to ratepayers and have no impact on EGD's financial statistics

Key Metrics

	2015A	2016E	2017E
AFFO/debt	12.00	13%-14%	13%-14%
Debt/EBITDA	6.58x	5.0x-5.5x	5.0x-5.5x

AFFO--Adjusted funds from operations. A--Actual. E--Estimated.

Business Risk: Excellent

EGD's excellent business risk profile reflects our assessment of the OEB regulatory framework that underpins the company's predictable and steady cash flow. In our view, the regulatory process is transparent, consistent, and predictable. Supporting consistency and predictability are the use of standard methodology applied to all utilities in its jurisdiction, including a transparent formula for allowed returns, and a consistent deemed capital structure that has not changed for many years. In addition, during times of change, the regulator follows a public process of study and consultation that allows management to adjust to new regulatory or market developments.

Gas distribution rates are typically determined in a timely fashion and allow for the recovery of prudently incurred operating and capital costs and the opportunity to earn a modest return. Furthermore, several mechanisms support timely recovery of material and unexpected capital costs, including rate riders and (in some circumstances) the ability to request a rate-reset hearing.

Under the Ontario regulatory regime, natural gas distributors, including EGD, have an obligation to ensure adequate supply of natural gas which increases operational risk; however, the company has been able to mitigate this with diverse sources of natural gas. The completion of the Greater Toronto Area (GTA) project will diversify EGD's sources of natural gas supply, including the Western Canada Sedimentary Basin (WCSB), Chicago, Dawn, and Niagara (Marcellus/Utica formations), as opposed to depending primarily on WCSB before. Furthermore, commodity costs (natural gas) flow through rates and are recovered through a quarterly adjustment mechanism, thereby limiting EGD's exposure to commodity risk and associated cash flow volatility.

Our view of the business risk assessment also reflects our expectation that the company's customer profile will be stable, with majority of the gas distribution revenues coming from residential customers, who are less sensitive to macroeconomic stresses and business cycles. However, demand for natural gas in the residential-based customer class can change due to weather-driven changes, plus the lack of weather normalization in the rate structure exposes EGD to volume risk which can result in cash flow volatility.

The utility's service territory covers most of Ontario's largest cities including the GTA, where new homes construction has surged. As a result, we expect the utility would also benefit from a modest uptick in new customer growth.

Financial Risk: Intermediate

Our assessment of EGD's financial risk profile is intermediate. We base this on our forecast AFFO-to-debt metric of 13%-14%, at the low end of the intermediate financial risk category during our outlook horizon. We use the low-volatility table when assessing the utility's cash flows to reflect the stability and predictability of the cash flow stream and that majority of the company's cash flows and operations are at the low end of the utility risk spectrum in gas distribution. In our forecast, we expect EGD to recover additional capital spending associated with the GTA project in the next cost-of-service application in 2019 subject to prudency testing.

In 2015, the Government of Ontario passed legislation to establish a cap and trade program (carbon tax) to meet greenhouse gas compliance obligation. The regulation came into effect on July 2016. We expect the tax to remain pass-through to rate-payers and should have no impact on EGD's financial performance.

Liquidity: Adequate

Our view on EGD's liquidity is adequate. We expect that liquidity sources will be adequate to cover uses at 1.11x in the next 12 months. We expect that, in the event of a 10% EBITDA decline, the company's sources of funds would still exceed its uses. In our view, EGD has sound relationships with its banks and generally prudent financial risk management. In the event of an unexpected financial stress situation, we believe the utility would scale back on its capital expenditures and has the flexibility to suspend dividend payments to preserve the credit metrics.

Principal Liquidity Sources	Principal Liquidity Uses
• Cash FFO of about C$650 million in the next 12 months • Committed credit facilities availability of about C$485 million as of September 2016, maturing in 2018	• Debt maturities of about C$500 million over the next 12 months • Capital expenditure of about C$520 million over the next 12 months • Dividends of about C$280 million over the next 12 months

Other Modifiers

We assigned a negative comparable rating analysis (CRA) modifier to EGD, reflecting credit metrics are at the low end of the financial risk profile. EGD's AFFO-to-debt was about 12% in 2015. During the outlook period, we project AFFO-to-debt of about 13%-14%, also consistent with the low end of the intermediate FRP, which warrants a negative CRA assessment.

Group Influence

We base our ratings of EGD on our SACP of the company, and our view that the subsidiary remains a core entity to the Enbridge group notwithstanding the parent's proposed friendly merger with Spectra Energy Corp.

We believe that EGD is unlikely to be sold, and that its operations in regulated gas distribution is integral to the overall group strategy of Enbridge, itself essentially a large diversified holding company with operations in transporting crude oil and natural gas gathering, transporting, treatment and processing operations. We believe that senior management has demonstrated a long-term commitment of support. The parent has a track record of providing equity and liquidity support to EGD as required. The subsidiary is successful at what it does, it has been operating for many years (so there is no startup risk), and we are not aware of any ongoing performance problems that could result in underperformance against the group management earnings targets. We believe the parent is well aware of the limited returns allowed for regulated utilities and has shown consistent support of the subsidiary during a period of major capital growth. Furthermore, the parent and subsidiary are closely linked and share the same brand.

However, in our view, there are insufficient insulating factors to achieve ratings separation between EGD and its parent, based on our criteria, so the final rating on the subsidiary is linked to that on Enbridge, resulting in a negative one-notch impact.

Ratings Score Snapshot

Corporate Credit Rating

BBB+/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Intermediate

- **Cash flow/Leverage:** Intermediate

Anchor: a

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Negative (-1 notch)

Stand-alone credit profile : a-

- **Group credit profile:** bbb+
- **Entity status within group:** Core (-1 notch from SACP)

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
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- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

S&P Global
Ratings

Research

Research Update:

Enbridge Gas Distribution Corporate Credit Rating Raised To 'A-' From 'BBB+' On Insulation Protection

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Research Update:

Enbridge Gas Distribution Corporate Credit Rating Raised To 'A-' From 'BBB+' On Insulation Protection

Overview

- We are raising our ratings on Enbridge Gas Distribution (EGD), including our long-term corporate credit and senior unsecured debt ratings to 'A-' from 'BBB+'.
- The upgrade reflects our view that the regulatory restriction and Enbridge's strategy with respect to EGD preserve the utility's credit strength and are consistent with our view of an insulated subsidiary.
- The stable outlook reflects our expectation that EGD will continue generating stable and predictable cash flows from its regulated gas distribution business.
- The stable outlook also reflects our expectation that Amalco (the combine entity from the potential amalgamation) will continue to be insulated and that the regulatory restriction and Enbridge's strategy toward Amalco to preserve the combine utilities' credit strength remains unchanged.

Rating Action

On Nov. 20, 2017, S&P Global Ratings raised its long-term corporate credit on Ontario-based utility operator Enbridge Gas Distribution (EGD) to 'A-' from 'BBB+'. S&P Global Ratings also raised its issue-level ratings on EGD's senior unsecured debentures to 'A-' from 'BBB+', its preferred stock global scale rating to 'BBB' from 'BBB-', and its preferred stock Canada scale rating to 'P-2' from 'P-2(Low)'. At the same time, S&P Global Ratings affirmed its 'A-1(Low)' Canada scale rating on the utility's commercial paper program. The outlook is stable.

Rationale

The upgrade reflects our view that the regulatory restriction and parent Enbridge Inc.'s strategy with respect to EGD will continue to preserve the utility's credit strength and are consistent with our view of insulation on a subsidiary. Specifically, the regulatory restriction limits EGD's business activities and requires the utility to maintain the common equity thickness at the regulatory deemed capital structure. This restriction will prevent the subsidiary from supporting the group to the extent that it would impair the utility's stand-alone creditworthiness. Furthermore, we expect that similar insulation features will continue through to the recently announced potential amalgamation of EGD and Union Gas Ltd. (UGL) that was announced on Nov. 2, 2017 with the filing of the merger, amalgamation, acquisition, and divestiture application to the Ontario Energy Board (OEB). In addition, we expect Enbridge's current strategy with respect to its regulated gas distribution utilities, including both EGD and UGL, will continue through Amalco (the combine entity from the potential amalgamation), preserving the credit strength of the regulated utilities.

Our view of EGD's business risk has not changed. The company continues to operate under a supportive regulatory regime. The OEB, the regulator for the Province of Ontario, continues to provide a transparent, consistent, and independently operated regulatory framework that supports a stable and predictable cash flow model, which we view as a key credit strength.

Under the current framework, natural gas distributors, including EGD, have an obligation to ensure an adequate supply of natural gas, which increases operational risk. The company has been able to mitigate this with diverse sources of natural gas. The recent completion of the Greater Toronto Area project will diversify EGD's sources of natural gas supply. Furthermore, commodity costs flow through rates and are recovered through a quarterly adjustment mechanism, thereby limiting EGD's exposure to commodity risk and associated cash flow volatility.

The business risk assessment also reflects our expectation that EGD's customer profile will be stable, with the majority of the customer base in the residential and small business segments, which are less sensitive to macroeconomic stresses and business cycles. However, demand for natural gas in the residential customer class can change due to weather-driven fluctuations, plus the lack of weather normalization in the rate structure exposes EGD to volume risk, which can result in cash flow volatility. We do not expect the utility's customer composition to change materially over the next two years.

We continue to assess EGD's financial measures against our most permissive leverage benchmarks because the majority of the utility's cash flow is generated from the low end of the utility risk spectrum in gas distribution under a highly supportive regulatory framework. During the outlook period, we forecast adjusted funds from operations (AFFO)-to-debt of about 12%-13%, consistent with the significant financial risk profile (FRP). As a result, we revised EGD's FRP to significant from intermediate and revised the comparable rating analysis modifier to neutral from negative. This has no impact to EGD's stand-alone credit profile (SACP).

Our base-case scenario includes the following assumptions:

- EGD continues to focus on its regulated natural gas distribution operations and its unregulated activities remain a relatively small part of its overall business and cash flow mix
- EGD does not experience any adverse and material regulatory decisions and that the regulatory regime remains transparent and stable
- EGD to earn close to its allowed return on equity on its deemed capital structure
- New customer growth of about 1% per year

- Dividend payout to the parent at 100% of operating cash flow
- Enbridge provides timely equity injection to EGD to maintain its deemed capital structure
- The cap and trade carbon tax to be a pass-through to ratepayers and have no impact on EGD's financial metrics

Liquidity

We view EGD's liquidity as adequate. We expect that liquidity sources will be adequate to cover uses more than 1.1x in the next 12 months. We expect that in the event of a 10% EBITDA decline, the company's sources of funds would still exceed its uses. In our view, EGD has sound relationships with its banks and generally prudent financial risk management. In the event of an unexpected financial stress situation, we believe the utility would scale back on its capital expenditures and has the flexibility to suspend dividend payments to preserve the credit metrics.

Principal liquidity sources are:

- Cash balance of C$3 million as of Sept. 30, 2017
- Cash funds from operations (FFO) of about C$570 million over the next 12 months
- Committed credit facilities availability of about C$245 million as of Sept. 30, 2017, maturing in 2019

Principal liquidity uses are:

- Debt maturities of C$200 million over the next 12 months
- Maintenance capital expenditure of about C$310 million over the next 12 months
- Dividends of about C$600 million over the next 12 months

Outlook

The stable outlook reflects our expectation that EGD will continue to generate stable and predictable cash flow. During the outlook period, we expect EGD's AFFO-to-debt to be about 12%-13%. In addition, the outlook reflects the consolidated outlook on parent Enbridge because S&P Global Ratings views EGD as an insulated subsidiary and allows the rating on the utility to be above the group credit profile (GCP).

Furthermore, the stable outlook reflects our expectation that EGD's insulation features will continue through to the new entity, Amalco, and Enbridge's strategy to preserve the combined utilities' credit strength will be unchanged.

Downside scenario

We could take a negative rating action on EGD should there be a material negative change in our assessment of the regulatory framework in Ontario, an increase in unregulated operations and cash flow beyond a modest amount, major cost overruns in its capital programs, or an adverse regulatory decision that results in our expectation that the utility's AFFO-to-debt will fall and stay below 11%.

In addition, we could lower the rating on EGD if we lower our GCP on Enbridge. This could happen if the parent's consolidated AFFO-to-debt ratio falls and stays below 11%, which could result from weaker financial performance due to mainline volumes falling below expectations, or more aggressive funding of the large combined capital program throughout our outlook period.

Alternatively, a negative rating action is possible if the company decides to amalgamate EGD and UGL without preserving the insulation provisions and credit quality of Amalco.

Upside scenario

A positive rating action on the utility is unlikely without an upgrade to the Enbridge GCP, which the consolidated rating on the parent determines, in conjunction with an upgrade to the SACP on EGD. This is because we cap our rating on the company at the lesser of the SACP or one notch above the GCP, given our assessment of the insulation measures in place that allow a one-notch separation as an insulated subsidiary.

An upgrade to EGD's SACP would require the company to improve financial measures with AFFO-to-debt approaching and staying above 14%, which could happen if the company's gas distribution margin increases substantially on a permanent basis. However, we do not expect this to happen during our outlook period, given rates are regulated.

An upgrade at the group level would require the company to improve financial measures with consolidated AFFO-to-debt above 15%-16% on a sustained basis. Given EGD's relatively small cash flow contribution to the Enbridge group, improvement to the company's financial measures alone would have a negligible impact on the ratings on Enbridge.

Ratings Score Snapshot

Corporate Credit Rating
A-/Stable/--

Business risk: Excellent
- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant
- Cash flow/Leverage: Significant

Anchor: a-

Modifiers

- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Financial policy: Neutral (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a-

- Group credit profile: bbb+
- Entity status within group: Insulated (no impact)

Issue Ratings

Capital structure

- EGD, the operating subsidiary, has about C$3,680 million of senior unsecured debentures.

Analytical conclusions

- Given that EGD is an investment-grade regulated utility and all the senior unsecured debt is at the operating subsidiary level, we do not consider it structurally subordinated. As a result, we equalize the issue-level rating on the unsecured debt with our 'A-' long-term corporate credit rating on the utility.

Related Criteria

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, Sept. 21, 2017
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings , April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Criteria - Insurance - General: Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008

Ratings List

Upgraded; Short-Term Rating Affirmed

	To	From
Enbridge Gas Distribution Inc.		
Corporate Credit Rating	A-/Stable/--	BBB+/Stable/--
Senior Unsecured	A-	BBB+
Preference Stock		
Global Scale	BBB	BBB-
Canada Scale	P-2	P-2(Low)
Commercial paper		
Canada Scale	A-1(Low)	

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on the S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

STANDARD & POOR'S
RATINGS SERVICES

Research

Union Gas Ltd.

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Union Gas Ltd.

Major Rating Factors

Corporate Credit Rating
BBB+/Stable/A-2

Strengths:

- Dominant market position in gas distribution within franchise area
- Regulated cash flows, which bolster stability
- No commodity risk

Weaknesses:

- Exposure to weather-induced variability in gas demand
- High leverage

Rationale

The ratings on Union Gas Ltd., an Ontario-based natural gas distribution company, reflect Standard & Poor's Ratings Services' view of the consolidated credit profile of its ultimate parent, Spectra Energy Corp. (BBB+/Stable/--), and Spectra's strong business risk profile and significant financial risk profile. We view the company's management and governance as "fair". Union Gas' monopoly-like market position, largely regulated asset base, and stable cash flow generation also support the ratings, in our opinion. We believe that the company's significant financial risk profile and softer key credit ratios counterbalance these strengths.

Union Gas is the second-largest natural gas distribution utility in Canada, serving approximately 1.4 million customers in northern, southwestern, and eastern Ontario. The company has a very diverse customer base, in our view, with a large portion of residential customers that reduces volatility due to stable energy demands. In addition, it owns the largest gas storage facility in Canada, with a working storage capacity of 156 billion cubic feet (at the Dawn Storage, near Sarnia, Ont.) and operates a transmission system from Dawn to Oakville, Ont., which we believe enhances business integration by providing customers value-added midstream services. As of Sept. 30, 2012, Union has about C$2.6 billion of adjusted long-term debt.

We believe the company has an excellent stand-alone business risk profile that reflects its efficient regulated gas distribution network, attractive franchise region in Ontario, strategic ownership of natural gas storage and transmission assets in southern Ontario, and a regulatory mechanism in place that allows for a complete flow-through of commodity cost expense to customers and permits the utility to adjust rates quarterly. The Ontario Energy Board (OEB) regulates the company's distribution operations under a cost-of-service model where operating and interest costs are covered, and Union Gas is allowed to earn an allowed return on equity (ROE).

The company operated under an OEB-approved five-year incentive regulation agreement that began in 2008. It will be using cost-of-service for 2013 after which we believe it will return to the incentive mechanism beginning in 2014. Although the OEB denied its applications for increasing its equity thickness and ROE to 40% and 9% from 36% and 8.54%, respectively, we do not expect a material impact on our forecast credit metrics -- it maintains the status quo. Like other utilities, the regulated rates of return provide cash flow stability and visibility, supporting our assessment of the excellent stand-alone business risk profile. Union Gas is exposed to changes in natural gas demand stemming from weather, which we expect to slightly depress EBITDA in 2012. However, the magnitude of the change does not present a rating concern, and forecasts are based on normal weather.

While more than 80% of the company's revenue comes from regulated distribution business, and regulated storage accounts for about another 10% of revenue, Union Gas has an unregulated storage business (about one-third of total storage capacity) that can introduce some earnings volatility and alter its business risk profile. Although the storage and transmission assets enhance operating flexibility and enable the company to manage its gas inventories, providing the benefit of supply security, the unregulated storage assets are subject to market rates and market demand and can affect earnings.

The ratings incorporate Standard & Poor's review of Union Gas' regulatory framework and how the regulation influences Spectra's actions. Our view that regulatory protection is robust reflects the OEB's power and the provisions in the undertakings agreement. The undertakings agreement between Spectra and the OEB governs the financial and business activity of Union Gas to ensure operating sustainability. Given the OEB's legislated power and the critical nature of natural gas distribution services to consumers (particularly for heating, which is Union Gas' primary business), should Spectra's credit profile deteriorate quickly, the OEB might initiate more comprehensive monitoring of Union Gas' financial position leading to more stringent regulation on the company's operations.

We continue to equalize the ratings on Union Gas with those on the parent. Nevertheless, in our view, regulatory protection (through the OEB) is such that the ratings on the company might not remain limited by the ratings on Spectra in the event that the latter begins to deteriorate--which is consistent with our rating methodology that allows for rating separation of a utility and its parent in specific circumstances. Accordingly, rating separation is possible if Spectra's operational viability becomes questionable.

Liquidity

Union Gas's liquidity is adequate, in our view. We expect sources of liquidity will be sufficient to cover uses more than 1.2x in the next 12 months. Key factors in our liquidity assessment include the following:

- We expect that even in the event of a 15% decline in EBITDA, sources of funds will exceed uses.
- Sources of liquidity include funds from operations (FFO) of approximately C$384 million, and committed facility availability of approximately C$305 million.
- Uses of funds consist of expected capital spending of C$405 million and distributions to the parent, Spectra, of about C$117 million.

We believe the company has a sound relationship with its banks, and good access to the capital markets

Furthermore, we believe that, if necessary, parent Westcoast Energy Inc. (BBB+/Stable/--) would provide financial support to Union Gas in the form of equity injections or reduced dividends to maintain its capital structure at the required regulatory levels should existing liquidity sources fall short.

Union Gas renewed its credit facility to 2016, but reduced the size to C$400 million from C$500 million. The company generally uses the facility to backstop a commercial paper program and for short-term funding purposes. This decline reflects the decline in natural gas prices--Union Gas purchases gas for consumers and flows the full cost to them.

The facility contains a covenant that limits the company's debt-to-capitalization to 75% and as of September 2012, Union Gas complied with the covenant. It has no debt maturities until 2014, at which time C$150 million of notes will become due. We believe that the company will be able to access markets to refinance its maturities.

Outlook

The stable outlook on Union Gas reflects our consolidated outlook on parent Spectra. We believe that a rating action on Spectra would most likely flow through to the ratings on Union Gas. However, a one-notch downgrade at Spectra would not necessarily negatively affect the ratings on Union Gas.

The stable outlook on Spectra Energy ratings reflects our expectation that leverage measures will remain in an acceptable range through a commodity price cycle. We also expect the company to focus growth on fee-based businesses. We expect continued stability to come from the regulated transmission, storage, and distribution operations. We think the company's FFO to debt ratio will be roughly 14% to 20% under most commodity price assumptions. If it appears that the company will maintain an FFO to debt ratio above or below this range, we could raise or lower the rating. We could also lower the ratings if the company aggressively pursues higher-risk growth opportunities, if it finances projects disproportionately with debt, or if it cannot execute key projects without driving costs notably over budget.

Rating Methodology

We analyze Union Gas using our investor-owned utility key credit factors and our criteria outlining parent-subsidiary relationships. We have equalized the ratings on the company with those of its parent, Spectra, which is consistent with our parent-subsidiary rating methodology and our belief that there are insufficient regulatory or legal barriers at this time to allow for ratings separation between the two entities.

Business Description

Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario. The distribution business serves more than 1.4 million residential, commercial, and industrial customers in more than 400 communities across Ontario. It provides storage and transportation services to customer at its Dawn Hub facility in Sarnia, Ont.

Strong Business Risk Profile

Market position and operating efficiency

Union Gas serves most of Ontario, excluding the Toronto and Ottawa metropolitan areas. Forty-five percent of its customer base is residential, providing a degree of predictability with respect to energy demand and earnings.

For the transmission system and storage assets the system's key competitive advantage is its large storage capacity, which enables efficient use of pipeline interconnections and is beneficial to customers. Several elements underpin Union Gas' competitive advantage in storage and transmission, including location, market liquidity, operating flexibility, and access to high-volume end users. Its entrenched position in these areas and large capital costs creates barriers to entry and potential rivals would find gaining market share difficult.

Operational risk in terms of gas storage relates to its operation of the Dawn storage facilities. There have been no noticeable operational interruptions. Storage costs for two-thirds of its business are passed through to the customers. The remaining third is unregulated. Dawn is one of the largest storage facilities in North America and has storage of 166 petajoules (PJ), peak day withdrawal of 2.8PJ a day, and peak day injections of 2.2PJ a day. Though there is a high amount of injections and withdrawals, the storage caverns have been operated since the 1950s and there is no history of material problems with the facilities.

Regulation

Union Gas operates under an OEB-approved five-year incentive regulation (IR) plan where it adjusts distribution rates annually based on the previous year's revenue and a number of adjustment factors. The company will be operating under cost-of-service regulation in 2013 as a test year but we expect a return to the incentive regulation method in 2014.

Although the OEB does not allow commodity price hedging, the exposure to the spot price is mitigated by the regulatory deferral mechanism in place. The difference between actual payment to gas suppliers and collection from the customers (which is based on the OEB-approved commodity rates) is treated as regulatory assets and liability. These accounts are settled quarterly. Furthermore, the OEB-approved rates (based on a forecast of market price for the next 12 months) are reviewed every quarter and can be adjusted if necessary. This insulates the company from commodity price volatility.

In the event of disallowance of commodity costs pass-through, there would be material negative credit implications, although we do not expect it. The OEB rejected Union Gas' most recent request to increase its ROE to 9% from 8.54% and equity thickness to 36% from 40%. The board found that a deemed common equity ratio of 36% is appropriate for the 2013 test year, consistent with the deemed common equity ratio in place from 2007-2012. As a result, allowed returns are the status quo.

Capital expenditures

Due to the decline of exports at its Kirkwall station, and the threat of unused Dawn-Kirkwall capacity, Union Gas has implemented the Kirkwall Flow Reversal Project, an expansion project designed to make Kirkwall fully bidirectional. The OEB agrees that Kirkwall station has changed substantially over the year and has directed the company to undertake a review of the allocation of Kirkwall metering costs as part of its updated cost allocation study and to file in its 2014 rates filing.

Spectra announced a memorandum of understanding with Enbridge Inc. and DTE Energy Co. to jointly develop the NEXUS Gas transmission system. The proposed project will originate in northeastern Ohio, include approximately 250 miles of large diameter pipe and be capable of transporting a billion cubic feet a day of natural gas. The line follows existing utility corridors to an interconnection in Michigan and uses the existing Vector Pipeline system to reach the Ontario market. The new pipeline will serve local distribution companies, power generators, and industrial users in the

Ohio, Michigan, and Ontario markets. It will include interconnects with Union Gas' Dawn hub. Although the project is still in the early stages, it does represent a potential for increases in regulated or long-term contracted cash flows for the company.

Significant Financial Risk Profile

Accounting

Union Gas reports in Canadian dollars and prepares it financial statements in accordance to U.S. generally accepted accounting principles (GAAP). The company switched from Canadian GAAP as of Jan. 1, 2012. We make several adjustments to Union Gas' debt figure, mainly postretirement benefits obligations, gas in storage, asset retirement obligations and operating lease adjustments. These collectively added about C$130 million to adjusted debt outstanding, or 5% of total debt (see table 1).

Table 1

Reconciliation Of Union Gas Ltd. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2011--									
Union Gas Ltd. reported amounts	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	2,655.0	1,501.0	1,813.0	618.0	413.0	152.0	354.0	354.0	147.0	290.0
Standard & Poor's adjustments										
Operating leases	26.1	N/A	N/A	1.7	1.7	1.7	3.8	3.8	N/A	9.2
Intermediate hybrids reported as equity	55.0	(55.0)	N/A	N/A	N/A	1.0	(1.0)	(1.0)	(1.0)	N/A
Postretirement benefit obligations	199.5	(299.2)	N/A	34.0	34.0	3.0	17.2	17.2	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	3.0	(3.0)	(3.0)	N/A	(3.0)
Asset retirement obligations	96.1	N/A	N/A	6.0	6.0	6.0	(7.9)	(7.9)	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	60.0	N/A	N/A
Minority interests	N/A	9.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Debt--other	(247.0)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	129.7	(345.2)	0.0	41.7	41.7	14.7	9.2	69.2	(1.0)	6.2
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	2,784.7	1,155.8	1,813.0	659.7	454.7	166.7	363.2	423.2	146.0	296.2

Table 1

Reconciliation Of Union Gas Ltd. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$) (cont.)

N/A--Not applicable.

Financial policy

Although Spectra determines financial policy, the regulated asset base with a deemed financial structure also influences the policy. The company provides gas loans from their holdings of gas in storage to other parties from its holdings of gas in storage. (Replacement cost of gas on loan is C$64 million as of Dec. 31, 2011) The parties are subject to the same credit policies used for all customers.

Cash flow adequacy

Union Gas' significant financial risk profile reflects what we believe is leverage that is high for the ratings and generally weak financial metrics. We forecast adjusted FFO-to-debt of approximately 14% in both 2013 and 2014, which reflects the stability of the company's cash flows. Our assumptions include a slight decline in EBITDA in 2012 from lower weather-related volumes, and modest improvements in 2013 back to the 2011 level. We expect capital expenditures to focus largely on maintenance capital in 2012, making up 85% of the approximately C$300 million budgeted for the year.

Table 2

Union Gas Ltd.--Peer Comparison

Industry Sector: Gas

	--Three-year averages--			
(Mil. C$)	**Union Gas Ltd.**	**Gaz Metro Inc.**	**Enbridge Gas Distribution Inc.**	**Terasen Gas Inc.**
Rating as of Dec. 21, 2012	BBB+/Stable/A-2	A-/Stable/--	A-/Stable/--	N.R.
Revenues	1,887.3	2,076.9	2,614.7	1,384.1
EBITDA	633.5	442.1	671.3	323.3
Net income from continuing operations	194.0	40.5	208.5	93.9
Funds from operations (FFO)	400.0	413.2	484.8	186.1
Capital expenditures	259.1	167.6	398.5	140.7
Dividends paid	167.3	92.9	203.7	78.5
Debt	2,613.0	1,954.8	2,793.3	1,761.5
Preferred stock	54.2	707.8	50.0	0.0
Equity	1,179.1	1,011.5	1,760.4	891.8
Debt and equity	3,792.2	2,966.3	4,553.7	2,653.3
Adjusted ratios				
EBITDA margin (%)	33.6	21.3	25.7	23.4
EBIT interest coverage (x)	2.6	2.5	2.3	2.0
FFO interest coverage (X)	3.3	4.4	3.5	2.5
FFO/debt (%)	15.3	21.1	17.4	10.6
Discretionary cash flow/debt (%)	(0.9)	7.9	1.9	(0.1)
Net cash flow/capex (%)	89.8	191.1	70.5	76.5
Total debt/debt plus equity (%)	68.9	65.9	61.3	66.4
Return on capital (%)	10.6	9.3	9.3	8.3
Return on common equity (%)	14.2	20.7	10.9	9.6

Table 2

Union Gas Ltd.--Peer Comparison (cont.)					
Common dividend payout ratio (unadjusted; %)	86.8	81.2		100.8	83.6

N.R.--Not rated.

Table 3

Union Gas Ltd.--Financial Summary					
Industry Sector: Gas					
	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2011**	**2010**	**2009**	**2008**	**2007**
Rating history	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2
Revenues	1,813.0	1,830.0	2,019.0	2,130.0	2,063.0
EBITDA	659.7	639.4	601.5	570.4	535.0
Net income from continuing operations	201.0	206.0	175.0	180.0	145.0
Funds from operations (FFO)	423.2	442.0	334.7	382.1	334.3
Capital expenditures	296.2	232.7	248.5	397.0	369.0
Dividends paid	146.0	307.0	49.0	117.5	38.5
Debt	2,784.7	2,739.1	2,315.3	2,581.4	2,223.1
Preferred stock	55.0	55.0	52.5	52.5	52.5
Equity	1,155.8	1,186.4	1,195.2	1,231.9	1,215.6
Debt and equity	3,940.5	3,925.5	3,510.5	3,813.2	3,438.7
Adjusted ratios					
EBITDA margin (%)	36.4	34.9	29.8	26.8	25.9
EBIT interest coverage (x)	2.7	2.6	2.4	2.4	2.3
FFO interest coverage (x)	3.5	3.5	2.9	3.3	3.2
FFO/debt (%)	15.2	16.1	14.5	14.8	15.0
Discretionary cash flow/debt (%)	(2.8)	(12.9)	15.7	(13.6)	(4.6)
Net cash flow/capex (%)	93.6	58.0	115.0	66.6	80.2
Debt/debt and equity (%)	70.7	69.8	66.0	67.7	64.6
Return on capital (%)	10.6	10.8	10.4	10.2	10.5
Return on common equity (%)	14.4	15.3	12.8	13.1	11.3
Common dividend payout ratio (unadjusted; %)	72.9	93.1	95.4	65.7	25.7

Related Criteria And Research

- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Criteria Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent, March 11, 2010
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

Ratings Detail (As Of December 21, 2012)	
Union Gas Ltd.	
Corporate Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Canadian CP Rating Scale	A-1(LOW)
Preferred Stock *Canadian Preferred Stock Rating Scale*	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+
Corporate Credit Ratings History	
02-Jan-2007	BBB+/Stable/A-2
13-Sep-2006	BBB/Positive/--
29-Jun-2006	BBB/Developing/--
Business Risk Profile	Strong
Financial Risk Profile	Significant
Related Entities	
Spectra Energy Capital LLC	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured	BBB
Spectra Energy Corp.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB
Spectra Energy Partners LP	
Issuer Credit Rating	BBB/Stable/A-2
Senior Unsecured	BBB
Texas Eastern Transmission L.P.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Westcoast Energy Inc.	
Issuer Credit Rating	BBB+/Stable/--
Commercial Paper	
Canadian CP Rating Scale	A-1(LOW)
Preferred Stock *Canadian Preferred Stock Rating Scale*	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

STANDARD & POOR'S RATINGS SERVICES

Research

Research Update:

Union Gas Ltd. Ratings On CreditWatch Negative Following Placement On Parent Spectra Energy Corp.

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Research Update:

Union Gas Ltd. Ratings On CreditWatch Negative Following Placement On Parent Spectra Energy Corp.

Overview

- We are placing our ratings on Union Gas Ltd. On CreditWatch with negative implications.
- The placement reflects that on parent Spectra Energy Corp.
- We will resolve this CreditWatch placement when we resolve the placement on Spectra.

Rating Action

On June 17, 2013, Standard & Poor's Ratings Services placed its ratings, including its 'BBB+' long-term corporate credit rating, on Union Gas Ltd. on CreditWatch with negative implications.

The CreditWatch placement follows that on parent Spectra Energy Corp.

Rationale

The ratings on Union Gas, an Ontario-based natural gas distribution company, reflect Standard & Poor's view of the consolidated credit profile of its ultimate parent, Spectra, and the parent's "strong" business risk profile, "significant" financial risk profile, and "satisfactory" management and governance score. Union Gas' monopoly-like market position, largely regulated asset base, and stable cash flow generation also support the ratings, in our opinion. We believe that the company's significant financial risk profile and softer key credit ratios counterbalance these strengths.

Union Gas is the second-largest natural gas distribution utility in Canada, serving approximately 1.4 million customers in northern, southwestern, and eastern Ontario. The company has a very diverse customer base, in our view, with a large portion of residential customers that reduces volatility due to stable energy demands. In addition, it owns the largest gas storage facility in Canada, with a working storage capacity of 156 billion cubic feet (at the Dawn Storage, near Sarnia, Ont.) and operates a transmission system from Dawn to Oakville, Ont., which we believe enhances business integration by providing customers value-added midstream services. As of March 31, 2013, Union has about C$2.8 billion of adjusted long-term debt.

We believe the company has an excellent stand-alone business risk profile that reflects its efficient regulated gas distribution network, attractive franchise region in Ontario, strategic ownership of natural gas storage and transmission assets in southern Ontario, and a regulatory mechanism in place that allows for a complete flow-through of commodity cost expense to customers and permits the utility to adjust rates quarterly. The Ontario Energy Board regulates the company's distribution operations under a cost-of-service model where operating and interest costs are covered, and Union Gas is allowed to earn an allowed return on equity.

CreditWatch

We will resolve the CreditWatch placement when we resolve the placement on Spectra.

Related Criteria And Research

- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- General Criteria: Stand-Alone Credit Profiles: One Component Of A Rating, Oct. 1, 2010
- Criteria Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent, March 11, 2010
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- 2008 Corporate Criteria: Ratios And Adjustments, April 15, 2008
- 2008 Corporate Criteria: Commercial Paper, April 15, 2008

Ratings List

Ratings Placed On CreditWatch Negative

Union Gas Ltd.

	To	From
Corporate credit rating	BBB+/Watch Neg/A-2	BBB+/Stable/A-2
Senior unsecured debt	BBB+/Watch Neg	BBB+
Preferred stock		
Global scale	BBB-/Watch Neg	BBB-
Canada scale	P-2(Low)/Watch Neg	P-2(Low)
Commercial paper		
Global scale	A-2/Watch Neg	A-2
Canada scale	A-1(Low)/Watch Neg	A-1(Low)

Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at www.spcapitaliq.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

STANDARD & POOR'S RATINGS SERVICES

Research

Research Update:

Union Gas Ltd. 'BBB+' Ratings Affirmed, Removed From CreditWatch Negative Following Downgrade To Parent

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Research Update:

Union Gas Ltd. 'BBB+' Ratings Affirmed, Removed From CreditWatch Negative Following Downgrade To Parent

Overview

- We are affirming our ratings, including our 'BBB+' long-term corporate credit rating, on Union Gas Ltd.
- We are also removing the ratings from CreditWatch, where they were placed June 17, 2013.
- The rating action follows our downgrade to Spectra Energy Corp. to 'BBB' from 'BBB+' after the drop-down of assets to subsidiary Spectra Energy Partners L.P.
- Based on our 'a-' stand-alone credit profile at Union Gas, the 'BBB' rating on Spectra Energy Corp., and our assessment of the regulatory insulation from the parent, we believe that a one-notch differential between the ratings on the parent and that on Union Gas is warranted.

Rating Action

On Nov. 4, 2013, Standard & Poor's Ratings Services affirmed its ratings, including its 'BBB+' long-term corporate credit rating on Ontario-based natural gas distribution company Union Gas Ltd. The outlook is stable. At the same time, Standard & Poor's removed the ratings on CreditWatch, where they were placed with negative implications June 17, 2013.

This affirmation follows today's downgrade to parent Spectra Energy Corp. to 'BBB' from 'BBB+' after the drop-down of assets to subsidiary Spectra Energy Partners L.P. Based on our 'a-' stand-alone credit profile (SACP) at Union Gas, the 'BBB' rating on Spectra, and our assessment of the regulatory insulation from the parent, we believe that a one-notch differential between the ratings on the parent and that on Union Gas is warranted.

Rationale

The ratings on Union Gas reflect Standard & Poor's view of the consolidated credit profile of its ultimate parent, Spectra, and the parent's "strong" business risk profile, "significant" financial risk profile, and "satisfactory" management and governance score. Union Gas' monopoly-like market position, largely regulated asset base, generally supportive regulatory framework, and stable cash flow generation support an "excellent" business risk profile and an 'a-' SACP, in our opinion. We believe that the company's "significant" financial risk profile and softer key credit ratios counterbalance these strengths.

Union Gas is the second-largest natural gas distribution utility in Canada, serving approximately 1.4 million customers in northern, southwestern, and eastern Ontario. The company has a very diverse customer base, in our view, with a large portion of residential customers that reduces volatility due to stable energy demands. In addition, it owns the largest gas storage facility in Canada, with a working storage capacity of 156 billion cubic feet (at the Dawn Storage, near Sarnia, Ont.) and operates a transmission system from Dawn to Oakville, Ont., which we believe enhances business integration by providing customers value-added midstream services. As of June 30, 2013, Union had about C$2.1 billion of adjusted long-term debt.

We believe the company has an excellent stand-alone business risk profile that reflects its efficient regulated gas distribution network, attractive franchise region in Ontario, strategic ownership of natural gas storage and transmission assets in southern Ontario, and a regulatory mechanism in place that allows for a complete flow-through of commodity cost expense to customers and permits the utility to adjust rates quarterly. The Ontario Energy Board regulates the company's distribution operations under a cost-of-service model where operating and interest costs are covered, and Union Gas is allowed to earn an allowed return on equity.

We view the financial risk profile as significant. Financial metrics are forecast to improve in 2013 due to improved gas distribution volumes from more normal weather. We expect no change in allowed returns and equity thickness in 2013. We forecast adjusted funds from operations (FFO) to debt in the 13-15% range in 2013 and 2014.

Liquidity

We view Union Gas Ltd.'s liquidity as "adequate" under our criteria for the next 12 months. Sources over uses are greater than 1.2x and sources less uses is positive.

Principal liquidity sources include the following:
- Expected FFO of C$340 million-C$360 million
- Committed credit facilities availability of C$190 million-C$210 million
- Debt issuance of C$240 million-C$260 million

Principal liquidity uses include the following:
- Capital expenditures of C$380 million-C$400 million
- Dividends of C$130 million-C$150 million
- Negative working capital of about C$140 million-C$150 million

Outlook

The stable outlook on Union Gas reflects our consolidated outlook on parent Spectra. We believe that further rating action on Spectra will flow through to the ratings on Union Gas. We believe that the 'a-' SACP at Union, coupled with our assessment of regulatory insulation from the parent, would cap the rating at the SACP.

The stable outlook on Spectra reflects our expectations that debt leverage measures will remain acceptable for the ratings under most commodity price assumptions and the company will maintain its focus on fee-based businesses. We expect the company's FFO-to-debt ratio will be 14%-15% in 2013 and 2014. If Spectra maintains this ratio notably below this range, we could lower the ratings. We could also lower the ratings if the company aggressively pursues higher-risk growth opportunities. An upgrade is unlikely during our two-year outlook period, but would require improved financial measures, with FFO-to-debt of more than 17% in most commodity price cycles.

Related Criteria And Research

- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Key Credit Factors: Criteria For Rating The Global Midstream Energy Industry, April 18, 2012
- Criteria Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent, March 11, 2010
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- 2008 Corporate Criteria: Ratios And Adjustments, April 15, 2008

Ratings List

Ratings Affirmed And Removed From CreditWatch Negative

Union Gas Ltd.

	To	From
Corporate credit rating	BBB+/Stable/A-2	BBB+/Watch Neg/A-2
Senior unsecured debt	BBB+	BBB+/Watch Neg
Preferred stock		
Global scale	BBB-	BBB-/Watch Neg
Canada scale	P-2(Low)	P-2(Low)/Watch Neg
Commercial paper		
Global scale	A-2	A-2/Watch Neg
Canada scale	A-1(Low)	A-1(Low) /Watch Neg

Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at www.spcapitaliq.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

Research

Research Update:

Union Gas Ltd. 'BBB+' Ratings Affirmed; Financial Risk Profile Revised To "Significant" From "Intermediate"

Primary Credit Analyst:
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Research Update:

Union Gas Ltd. 'BBB+' Ratings Affirmed; Financial Risk Profile Revised To "Significant" From "Intermediate"

Overview

- Increased capital expenditures to finance the Dawn-Parkway facility expansion have tightened credit metrics for Union Gas Ltd., moving the financial risk profile into the "significant" category from "intermediate."
- We also removed the negative comparative ratings modifier we had used to highlight the possible shift in the financial risk profile.
- As a result, there is no change to the 'a-' stand-alone credit profile, and we are affirming our ratings on Union, including our 'BBB+' long-term corporate credit rating.
- We expect the company to keep its financial metrics stable at the high end of the significant financial risk profile during this period of capital expenditures.

Rating Action

On Aug. 29, 2014, Standard & Poor's Ratings Services affirmed its ratings on Ontario-based natural gas distribution company Union Gas Ltd, including its 'BBB+' long-term corporate credit rating. The outlook is stable.

Rationale

Union's Dawn-Parkway facility expansion is one of Union's largest capital expenditure to date. Although the Ontario Energy Board (OEB) has approved recovery of costs for the project, the expenditures have tightened the company's credit metrics in the medium term. As a result, we are revising our financial risk profile on Union to "significant" from "intermediate." We expect credit metrics to remain at the high end of the significant category as the company continues with its large capital program and subsequent recovery of costs through rates.

We view Union's business risk profile as "excellent," with an "excellent" competitive position that reflects the company's efficient regulated gas distribution network, its attractive franchise region in Ontario, its strategic ownership of natural gas storage and transmission assets in southern Ontario, and a regulatory mechanism that allows for a complete flow-through of commodity cost expense to customers and permits the utility to adjust rates quarterly. The OEB regulates Union's distribution operations under an incentive-based regulatory model from 2014 -2018. We view the regulatory environment as generally stable and transparent, and expect that the company will achieve the expected productivity gains and earn its allowed return on equity (ROE) at a minimum.

Although more than 80% of Union's revenue comes from regulated distribution business, and regulated storage accounts for about another 10% of revenue, the company has an unregulated storage business (about one-third of total storage capacity) that can introduce some earnings volatility and alter its business risk profile. Seasonal storage spreads had been weak through 2013, and we expect that to continue for the next 12-24 months. The storage and transmission assets enhance operating flexibility and enable Union to manage its gas inventories, providing the benefit of supply security, but the company's unregulated storage assets are subject to market rates and market demand and can affect earnings.

We assess Union's financial risk profile as "significant." We forecast that adjusted funds from operations (AFFO)-to-debt will be approximately 12% during our two-year outlook horizon. We expect capital expenditures to be higher than average in 2014 and 2015 as Union expands its distribution infrastructure. We also expect that the company will earn its allowed 8.93% ROE over the five-year term of its incentive-rate mechanism. We assign a neutral comparable rating analysis modifier to Union, having revised it from negative. The negative modifier reflected our expectation that financial metrics could weaken if the regulator approved large expansion projects, which has happened.

Our base-case scenario assumes the following:
- The company will earn its allowed 8.93% ROE
- Capital expenditures of approximately C$475 million per year for the next two years
- Dividend policy will remain consistent

Based on these assumptions, we arrive at the following credit measures for the next two years:
- AFFO-to-debt of about 12%
- Debt-to-EBITDA of approximately 5.4x

Liquidity

We view Union's liquidity as "adequate" with sources less uses being positive, and sources divided by uses as being greater than 1.1x. Even in the event of a 15% decline in EBITDA, the company's sources will still exceed its uses. We believe it is likely able to absorb, without refinancing, high-impact, low probability events.

Principal liquidity sources include the following:
- FFO of approximately C$375 million-C$390 million
- Credit facility availability of C$350 million

Principal liquidity uses include the following:
- Capex of approximately C$450 million

- Cash dividends of C$100 million-C$110 million

Outlook

The stable outlook on Union reflects our consolidated outlook on ultimate parent Spectra Energy Corp. We believe that a rating action on Spectra will flow through to the ratings on Union Gas. We also believe that the 'a-' stand-alone credit profile (SACP) at Union Gas, coupled with our assessment of regulatory insulation from the parent, would cap the rating at the SACP.

The stable outlook on Spectra reflects our expectation that debt leverage measures will remain acceptable for the rating under most commodity price assumptions and the company will maintain its focus on fee-based businesses. We expect Spectra's FFO-to-debt ratio will be 14%-15% in 2014.

Downside scenario

A decline in adjusted funds from operations to debt to below 9% at Union could lower the SACP; however, we would not lower the rating on the company unless the SACP equaled the group credit profile on Spectra.

Upside scenario

An upgrade is unlikely without an upgrade to the group credit profile, which the consolidated credit rating on Spectra determines. Our rating on Union is capped at the lessor of the SACP or one notch above the group credit profile, given our assessment of the regulatory and structural ring-fencing provisions that allow a one notch separation as an insulated subsidiary.

Ratings Score Snapshot

Corporate Credit Rating: BBB+/Stable/A-2

Business risk: Excellent
- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant
- Cash flow/Leverage: Significant

Anchor: a-

Modifiers
- Diversification: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Financial policy: Neutral (no impact)

- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a-

Group credit profile: bbb
- Entity status within group: insulated subsidiary (-1 notch from SACP)

Related Criteria And Research

Related Criteria
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Jan. 2, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Ratings List

Ratings Affirmed

Union Gas Ltd.	
Corporate credit rating	BBB+/Stable/A-2
Senior unsecured debt	BBB+
Preferred stock	
Global scale	BBB-
Canada scale	P-2(Low)
Commercial paper	
Global scale	A-2
Canada scale	A-1(Low)

Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at www.spcapitaliq.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

Research

Summary:
Union Gas Ltd.

Primary Credit Analyst:
Gerald F Hannochko, Toronto (1) 416-507-2589; gerald.hannochko@standardandpoors.com

Secondary Contact:
Stephen R Goltz, Toronto (1) 416-507-2592; stephen.goltz@standardandpoors.com

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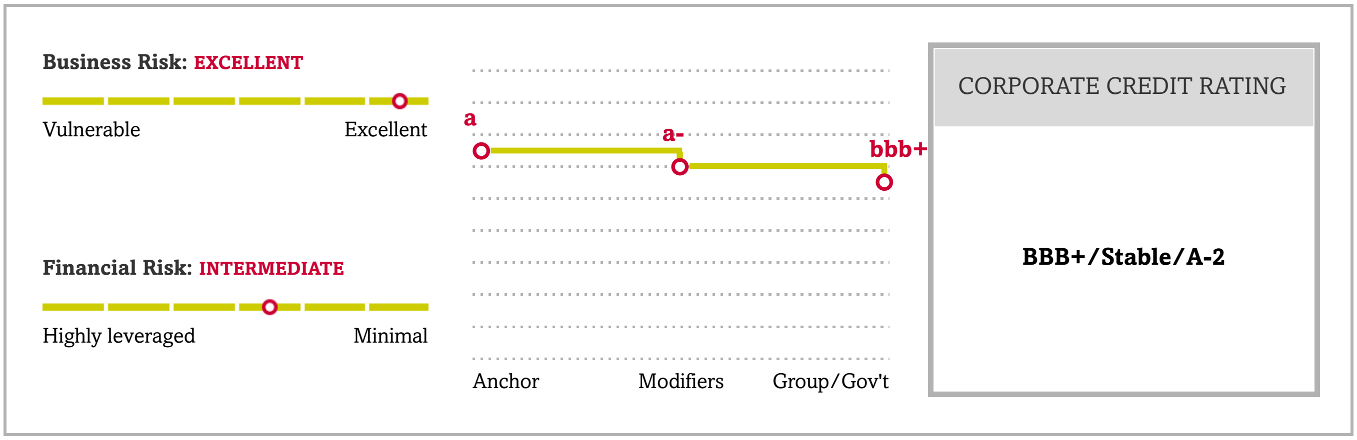
Summary:

Union Gas Ltd.



Rationale

Business Risk: Excellent	Financial Risk: Intermediate
• Regulated gas distribution monopoly in Ontario, with very low country and industry risk • Transition to incentive-based ratemaking from a cost-of-service ratemaking year in 2013, which Standard & Poor's Ratings Services doesn't expect to affect cash flows	• Stable financial metrics throughout our forecast period • Expected earnings of at least the previously allowed cost-of-service return on equity (ROE) under the incentive-rate mechanism

Outlook: Stable

The stable outlook on Union Gas Ltd. reflects our consolidated outlook on ultimate parent Spectra Energy Corp. We believe that a rating action on Spectra will flow through to the ratings on Union Gas. We believe that the 'a-' SACP at Union Gas, coupled with our assessment of regulatory insulation from the parent, would cap the rating at the stand-alone credit profile (SACP).

The stable outlook on Spectra reflects our expectation that debt leverage measures will remain acceptable for the rating under most commodity price assumptions and the company will maintain its focus on fee-based businesses. We expect Spectra's funds from operations (FFO)-to-debt ratio will be 14%-15% in 2014.

Downside scenario

A decline in adjusted funds from operations to debt to below 9% could lower the SACP; however, we would not lower the rating unless the SACP equaled the group credit profile.

Upside scenario

An upgrade is unlikely without an upgrade to the group credit profile, which is determined by the consolidated credit rating on parent Spectra. Union gas' credit rating is capped at the lessor of the SACP or one notch above the GCP given our assessment of the regulatory and structural ring-fencing provisions that allow a one notch separation as an insulated subsidiary.

Standard & Poor's Base-Case Scenario

Assumptions

- Expected earnings of at least its previously allowed cost-of-service ROE under the incentive-rate mechanism
- Incentive-based earnings based on an escalation factor of 40% of inflation, continued pass-through of commodity costs, and an earnings sharing mechanism that would see Union keep up to a 9.9% of ROE
- A rate base that will fully include a capital program of approximately C$300 million
- Dividends to Westcoast Energy Inc., its immediate parent, of approximately C$150 million

Key Metrics

	2013A	2014E	2015E
EBITDA Margin	32.5%	33%–35%	33%–35%
AFFO/debt	13.6%	13%-14%	13%–14%
Debt/EBITDA	5.0x	4.5x–5.5x	4.5x–5.5x

AFFO--Adjusted funds from operations. A--Actual. E--Estimate.

Business Risk: Excellent

We view Union's business risk profile as "excellent," with an "excellent" competitive position that reflects its efficient regulated gas distribution network, attractive franchise region in Ontario, strategic ownership of natural gas storage and transmission assets in southern Ontario, and a regulatory mechanism that allows for a complete flow-through of commodity cost expense to customers and permits the utility to adjust rates quarterly. The Ontario Energy Board (OEB) regulates Union Gas' distribution operations under an incentive-based regulatory model from 2014 -2018. We view the regulatory environment as generally stable and transparent, and we expect that the company will be able to achieve the expected productivity gains and earn its previously allowed ROE at a minimum.

Although more than 80% of Union Gas' revenue comes from regulated distribution business, and regulated storage accounts for about another 10% of revenue, the company has an unregulated storage business (about one-third of total storage capacity) that can introduce some earnings volatility and alter its business risk profile. Seasonal storage spreads have been weak through 2013, and we expect that to continue for the next 12-24 months. The storage and transmission assets enhance operating flexibility and enable Union Gas to manage its gas inventories, providing the benefit of supply security, but the unregulated storage assets are subject to market rates and market demand and can affect earnings.

Financial Risk: Intermediate

We assess Union Gas' financial risk profile as "intermediate." We forecast that AFFO-to-debt will be approximately 13% during our two-year outlook horizon. We expect capital expenditures to be slightly higher than average in 2014 and 2015 as Union Gas expands its distribution infrastructure.

Liquidity: Adequate

We view liquidity as "adequate." Sources less uses is positive, and sources over uses is greater than 1.1x. We believe the company will continue to have solid relationships with its banks, a generally high standing in credit markets, and generally prudent risk management.

Principal Liquidity Sources	Principal Liquidity Uses
• FFO of C$400 million–C$420 million • Credit revolver availability of C$90 million-C$110 million	• Capital expenditures of C$280 million–C$300 million • Cash dividends of C$140 million-C$150 million

Other Modifiers

We assess the comparable rating analysis modifier to be negative, reflecting our view that financial metrics might deteriorate if the regulator approves large capital programs.

Group Influence

We view Union Gas to be an insulated subsidiary to immediate parent Westcoast Energy and ultimate parent Spectra Energy, because we believe that there are structural and legal ring-fencing measures that allow for a one-notch uplift from the group credit profile of 'bbb', equivalent to the rating on Spectra.

Ratings Score Snapshot

Corporate Credit Rating

BBB+/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Intermediate

- **Cash flow/Leverage:** Significant

Anchor: a

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Financial policy:** Neutral (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Negative (-1 notch)

Stand-alone credit profile : a-

- **Group credit profile:** bbb
- **Entity status within group:** Insulated (-1 notch from SACP)

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Jan. 2, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013

- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

Research

Summary:
Union Gas Ltd.

Primary Credit Analyst:
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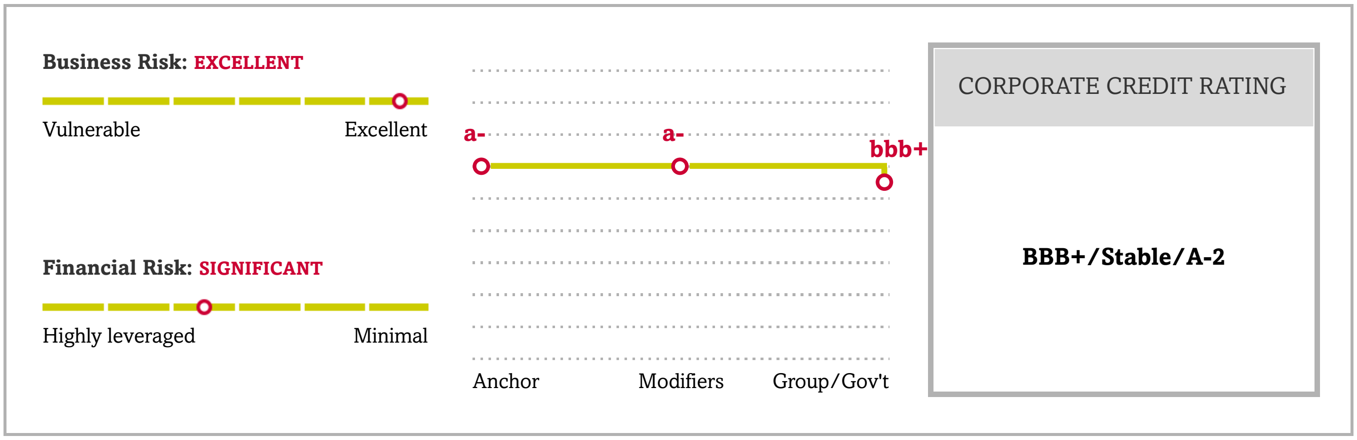
Summary:

Union Gas Ltd.



Rationale

Business Risk: Excellent	Financial Risk: Significant
• Regulated gas distribution monopoly in Ontario, with very low country and industry risk • A relatively transparent and predictable regulatory regime, with passed-through commodity costs • Union Gas Ltd.'s ability to recover all its fixed and variable operating costs	• Stable financial metrics throughout Standard & Poor's Ratings Services' forecast period • Expected earnings of at least the previously allowed cost-of-service return on equity (ROE) under the incentive-rate mechanism

Outlook: Stable

The stable outlook on Union reflects our consolidated outlook on ultimate parent Spectra Energy Corp. We believe Union gas to be "strategically important" to Spectra under our group rating methodology.

The stable outlook on Spectra reflects our expectation that debt leverage measures will remain in an acceptable range for the rating under most commodity price assumptions and the company will maintain its focus on fee-based businesses. We expect Spectra's funds from operations (FFO)-to-debt ratio will be about 14% in 2015.

Downside scenario

Although we don't expect it, a material, adverse regulatory ruling or a significant increase in leverage leading to sustained deterioration in forecast adjusted FFO (AFFO)-to-debt below 9% could lead to a downgrade.

We could also lower the rating if we lower our group credit profile (GCP) on Spectra. This could happen if the company's FFO-to-debt ratio falls notably below 14% or it aggressively pursues higher-risk growth opportunities that change its business risk profile or pressures its credit metrics.

Upside scenario

An upgrade is unlikely without an upgrade to the GCP, which the consolidated rating on the parent determines. A higher rating would require Spectra to embrace more conservative financial policies and to improve financial measures, with FFO-to-debt of about 25% in most commodity price cycles.

We cap our rating on Union Gas at the lesser of the stand-alone credit profile or one notch above the GCP given our assessment of the regulatory and structural ring-fencing provisions that allow a one notch separation as an insulated subsidiary. Based on our current forecast and the company's current financial policy, which we do not expect will change, we believe the prospect of an upgrade is limited during our two-year outlook horizon.

Standard & Poor's Base-Case Scenario

Assumptions

- The regulatory regime will be relatively stable, and Union Gas will not experience any material, adverse regulatory decisions
- The company will continue to earn close to its allowed ROE on its deemed capital structure
- It will not make any material, debt-financed unregulated investments
- Rates in 2015 and 2016 will be established by the regulator under the OEB's incentive-rate mechanism (IRM)
- Dividends to Westcoast Energy Inc., its immediate parent, of C$100 million-C$125 million

Key Metrics

	2014A	2015E	2016E
AFFO/debt	12.8%	12%-14%	12%–14%
Debt/EBITDA	5.3x	5.0x–6.0x	5.0x–6.0x

AFFO--Adjusted funds from operations. A--Actual. E--Estimate.

Business Risk: Excellent

We view Union Gas' business risk profile as "excellent." We believe the company has an "excellent" competitive position, reflecting its efficient regulated gas distribution network, attractive franchise region in Ontario, strategic ownership of natural gas storage and transmission assets in southern Ontario, and a regulatory mechanism that allows for a complete flow-through of commodity cost expense to customers and permits the utility to adjust rates quarterly.

The Ontario Energy Board (OEB) regulates Union Gas' distribution operations under an incentive-based regulatory model from 2014 -2018. We view the regulatory environment as generally stable and transparent, and we expect the company will be able to achieve the expected productivity gains and earn its previously allowed ROE at a minimum.

Although more than 80% of Union Gas' revenue comes from regulated distribution business, and regulated storage accounts for about another 10% of revenue, the company has an unregulated storage business (about one-third of total storage capacity) that can introduce some earnings volatility and alter its business risk profile. The storage and transmission assets enhance operating flexibility and enable Union Gas to manage its gas inventories, providing the benefit of supply security, but the unregulated storage assets are subject to market rates and market demand and can affect earnings.

Financial Risk: Significant

We assess Union Gas' financial risk profile as "significant." We forecast that AFFO-to-debt will be 12%-14% during our two-year outlook horizon. We expect capital expenditures to be slightly higher than average in 2015 as the company expands its distribution infrastructure.

Liquidity: Adequate

We view liquidity as "adequate." Sources less uses is positive, and sources over uses is greater than 1.1x. We believe Union Gas will continue to have solid relationships with its banks, a generally high standing in credit markets, and generally prudent risk management.

Principal Liquidity Sources	Principal Liquidity Uses
• FFO of C$400 million–C$420 million • Revolver availability of C$500 million, expiring in 2019	• Capital spending of C$400 million-C$450 million in 2015 • A debt maturity of C$150 million in 2015 • Dividends of C$100 million-C$120 million in 2015

Group Influence

We view Union Gas to be an insulated subsidiary to immediate parent Westcoast and ultimate parent Spectra Energy, because we believe that there are structural and legal ring-fencing measures that allow for a one-notch uplift from the 'bbb' GCP, equivalent to the rating on Spectra.

Ratings Score Snapshot

Corporate Credit Rating

BBB+/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)

- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** bbb
- **Entity status within group:** Strategically important (-1 notch from SACP)

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

S&P Global
Ratings

Research

Research Update:

Union Gas Ltd. On Watch Positive On Proposed Friendly Merger Between Enbridge Inc. And Spectra Energy Corp.

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Secondary Contact:
Stephen R Goltz, Toronto (416) 507-2592; stephen.goltz@spglobal.com

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Research Update:

Union Gas Ltd. On Watch Positive On Proposed Friendly Merger Between Enbridge Inc. And Spectra Energy Corp.

Overview

- On Sept. 6, 2016, Enbridge Inc. announced its proposed C$37 billion (US$28 billion) friendly merger with Spectra Energy Corp., the ultimate parent company of Union Gas Ltd.
- As a result, we are placing our 'BBB+' long-term corporate credit and senior unsecured debt ratings on Union on CreditWatch with positive implications.
- The CreditWatch placement solely reflects the application of our group rating methodology criteria and our expectation that Union would likely be considered a core asset and remain an insulated subsidiary to the Enbridge group. We would likely raise our ratings on Union after the merger closes.
- We are also placing our 'BBB-' global scale and 'P-2(Low)' Canada scale preferred shares ratings on Union on CreditWatch with positive implications to reflect the flow-through impact on the potential upgrade.

Rating Action

On Sept. 6, 2016, S&P Global Ratings placed its 'BBB+' long-term corporate credit and senior unsecured debt ratings on Ontario-based regulated gas distributor Union Gas Ltd. on CreditWatch with positive implications based the announcement of the proposed friendly merger between Enbridge Inc. and Spectra Energy Corp., the ultimate parent of Union. At the same time, S&P Global Ratings placed its 'BBB-' global scale and 'P-2(Low)' Canada scale preferred shares ratings on CreditWatch with positive implications to reflect the flow-through impact of the potential upgrade on Union.

Rationale

The CreditWatch placement follows Enbridge's announcement of its C$37 billion (US$28 billion) proposed friendly merger with Spectra, which is the parent of Union at present. The CreditWatch placement solely reflects the application of our group rating methodology (GRM) criteria. Under our GRM framework, our ratings on Union are capped at one notch above our 'bbb' group credit profile (GCP) on Spectra, the current parent of Union, despite our 'a-' stand-alone credit profile (SACP) on Union. This is because existing structural and legal ring-fencing measures for Union only allows for a one-notch differential between the Union SACP and the Spectra GCP.

On close of the transaction we expect to maintain our 'BBB+' ratings and 'bbb+' GCP on Enbridge, which will become the new ultimate parent of Union. In addition, we expect Union would be a core asset and remain an insulated subsidiary under Enbridge. Furthermore, we expect existing structural and legal ring-fencing measures to remain unchanged, which continues to allow for a one-notch separation between our ratings on Union and our GCP on its parent. As a result, we could raise our ratings on Union to 'A-', one notch above our GCP on Enbridge.

CreditWatch

We will resolve the CreditWatch placement on Union once we resolve that on Spectra. This includes determining the final GCP on Enbridge following the closing of the transaction and our review of Union's strategic importance to Enbridge including the structural and legal ring-fencing provisions.

Ratings Score Snapshot

Corporate Credit Rating: BBB+/Watch Pos/--

Business risk: Excellent
- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant
- Cash flow/Leverage: Significant

Anchor: a-

Modifiers
- Diversification: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Financial policy: Neutral (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a-
- Group credit profile: bbb
- Entity status within group: Insulated Subsidiary (-1 notch from SACP)

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - Industrials: Key Credit Factors For The Midstream Energy Industry, Dec. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios and Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Country Risk Assessment Methodology and Assumptions, Nov. 19, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008

Ratings List

Placed On CreditWatch

	To	From
Union Gas Ltd.		
Corporate credit rating	BBB+/Watch Pos/--	BBB+/Stable/--
Senior unsecured	BBB+/Watch Pos	BBB+
Preferred stock		
Global scale	BBB-/Watch Pos	BBB-
Canada scale	P-2(Low)/Watch Pos	P-2(Low)

Ratings Affirmed

Union Gas Ltd.	
Corporate credit rating	--/--/A-2
Union Gas Ltd.	
Commercial paper	
Canada scale	A-1(LOW)
Global scale	A-2

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at www.spcapitaliq.com. All ratings affected by this rating action can be found on the S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

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S&P Global
Ratings

Research

Summary:
Union Gas Ltd.

Primary Credit Analyst:
Andrew Ng, Toronto (416) 507-2545; andrew.ng@spglobal.com

Secondary Contact:
Stephen R Goltz, Toronto (416) 507-2592; stephen.goltz@spglobal.com

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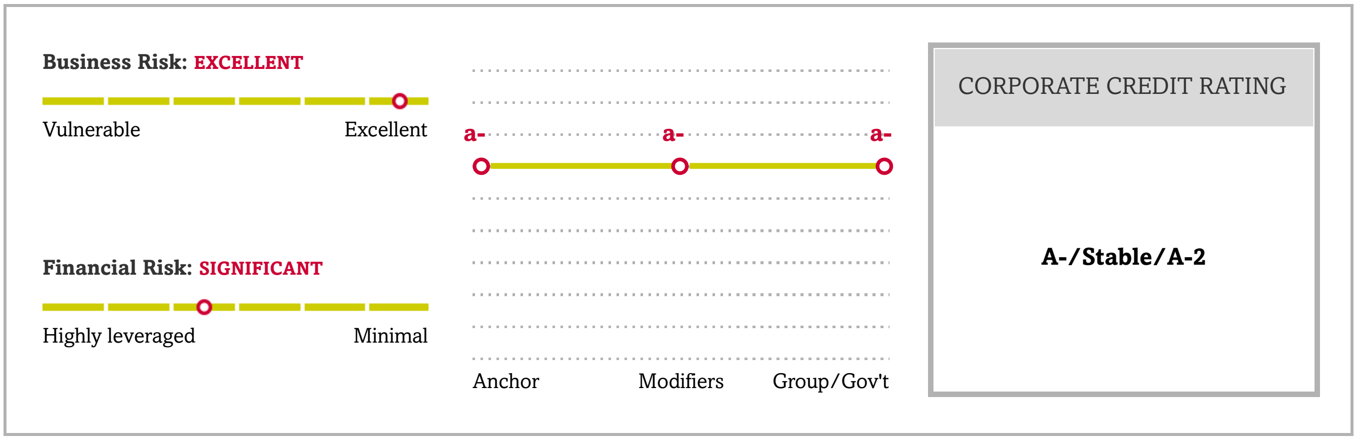
Summary:

Union Gas Ltd.



Rationale

Business Risk: Excellent	Financial Risk: Significant
• A relatively transparent and predictable regulatory regime • Natural gas and carbon tax costs that are passed through to rate payers • Limited geographical and regulatory diversity, with operations only in Ontario	• Stable, regulated cash flow • Capital programs spending to wind down in 2018 after the completion of the Dawn-Parkway Expansion project • Reliance on Enbridge Inc. (Enbridge), the parent, or its affiliates to provide timely equity injection to maintain deemed capital structure

Outlook: Stable

The stable outlook on Union Gas Ltd. reflects S&P Global Ratings' expectation that the company will continue to generate stable and predictable cash flows from its regulated gas distribution operation. We also expect Union will execute its planned capital programs on time and on budget.

The stable outlook also reflects our view that Enbridge, the parent, will maintain adjusted funds from operations (AFFO)-to-debt at the low end of the significant financial risk profile category, at 13%-14% through 2019. We believe that Enbridge will need to finance its aggressive capital program over the next two years with equity and hybrids to maintain financial metrics in the significant category.

Furthermore, the stable outlook on Union reflects our expectation that the company's insulation features will continue through to the potential new entity, Amalco, should Enbridge merge Union with Enbridge Gas Distribution Inc. (EGD); and Enbridge's strategy to preserve the combined utilities' credit strength will not change.

Downside scenario

We could lower the ratings on Union if the company experiences material operational issues, delays and cost overruns in capital projects implementation or adverse material regulatory decisions that leads to sustained deterioration in forecast AFFO-to-debt approaching 9% with no prospect of improvements.

Alternatively, we could also lower the rating on Union if we lower our group credit profile (GCP) on Enbridge. This could happen if Enbridge's consolidated AFFO-to-debt stays below 13% or debt-to-EBITDA remains above 5.5x, which could result from weaker financial performance due to mainline volumes falling below expectations, or a more aggressive funding of the large combined capital program throughout our outlook period.

Furthermore, we could also lower the rating on Union if Enbridge decides to amalgamate EGD and Union without preserving Amalco's insulation provisions and credit quality.

Upside scenario

An upgrade to Union is unlikely without an upgrade to the Enbridge GCP, which the consolidated rating on the parent determines, in conjunction with an improved stand-alone credit profile (SACP) on Union. This is because we cap our rating on Union at the lesser of the SACP or one notch above the GCP, given our assessment of the regulatory and structural ring-fencing provisions that allow a one notch separation as an insulated subsidiary.

An upgrade to Union's SACP would require the company to improve financial measures, with sustained AFFO-to-debt approaching 14%, which could happen if the company's gas distribution revenue increases substantially and permanently. However, we do not expect this to happen during our outlook period, given the regulated rates. An upgrade to Enbridge's GCP would require Enbridge to maintain AFFO-to-debt above 16%-17% or debt-to-EBITDA below 4.5x; and maintain the combined entity's increased scale, scope, and diversity. Given that Union's cash flow contribution to the Enbridge group is relatively small, improvement to Union's financial measures alone would have a negligible impact on the ratings on Enbridge.

Our Base-Case Scenario

Assumptions

- Union continues to continue focus on its regulated natural gas distribution operations and unregulated activities remain a relatively small part of overall business and cash flow mix
- It does not experience any adverse and material regulatory decisions and that the regulatory regime remains transparent and stable
- The company will earn close to its allowed return on equity on its deemed capital structure
- New customer growth will be about 1% per year
- There will be no dividends for fiscal 2017; dividends resume in fiscal 2018
- Enbridge, the parent, or its affiliates to provide timely equity injection to Union to maintain its deemed capital structure
- The cap and trade carbon tax will be a pass-through to ratepayers and have no impact on the company's financial metrics

Key Metrics

	2016A	2017E	2018E
AFFO/debt	10.5%	About 11%	11%-12%
Debt/EBITDA	5.7x	About 6x	About 6x

Note: Fully S&P Global Ratings-adjusted. AFFO--Adjusted funds from operations. A--Actual. E--Estimated.

Business Risk: Excellent

Our view of Union's business risk is unchanged. The utility continues to operate under the Ontario Energy Board's regulatory framework, which underpins its predictable and stable cash flow. The approved revenue requirement includes all operating, interest, and capital expenses and the opportunity to earn a modest return. In addition, several mechanisms support timely recovery of material and unexpected capital costs, including rate riders and (in some circumstances) the ability to request a rate-reset hearing.

Under the current framework, natural gas distributors, including Union, must ensure an adequate supply of natural gas, which increases operational risk. The company has mitigated this with diverse sources of natural gas. The recent completion of the Dawn-Parkway Expansion project allows Union to gain access to cheaper gas supply and to diversify its sources of gas supply. In addition, commodity costs flow through rates and are recovered through a quarterly adjustment mechanism, thereby limiting the company's exposure to commodity risk and associated cash flow volatility. Furthermore, the cap and trade carbon tax, recently introduced by the Ontario government, is also a flow-through to ratepayers and has no impact on the utility's financial measures.

The business risk assessment also reflects our expectation that Union's customer profile will be stable, with the majority of the customer base in the residential and small business segments, which are less sensitive to macroeconomic stresses and business cycles. However, demand for natural gas in the residential customer class can change due to weather-driven fluctuations, plus the lack of weather normalization in the rate structure exposes Union to volume risk, which can result in cash flow volatility. We do not expect the utility's customer composition to change materially over the next two years. However, the magnitude of the change does not present a rating risk, and forecasts are based on normalized weather.

Financial Risk: Significant

Our view of Union's financial risk is also unchanged. We continue to assess the company's financial measures against our most permissive leverage benchmarks because the majority of cash flow comes from the low end of the utility risk spectrum in gas distribution under a highly supportive regulatory framework. During the outlook period, we forecast AFFO-to-debt of about 11% in 2017 before improving to 11%-12% in 2018, following the Dawn-Parkway project's completion. Debt leverage will be high, with debt-to-EBITDA of about 6x in both 2017 and 2018. Modest growth in new customers of about 1% per year should slightly offset pressure on credit metrics.

Liquidity: Adequate

Our view of Union's liquidity is adequate. We expect that liquidity sources will be adequate to cover uses more than 1.1x in the next 12 months. We also expect that, in the event of a 10% EBITDA decline, the company's sources of funds would still exceed its uses. In our opinion, Union has sound relationships with its banks and generally prudent financial risk management. In the event of unexpected financial stress, we believe the utility would scale back on its capital expenditures and has the flexibility to suspend dividend payments to preserve the credit metrics.

Principal Liquidity Sources	Principal Liquidity Uses
• Cash on hand of about C$31 million as of Sept 30, 2017 • Projected FFO of about C$520 million over the next 12 months • Committed credit facilities availability of about C$30 million (net of C$670 million commercial paper backstop) as of Sept 30, 2017, expiring in 2021 • Proceeds from debt issuances of about C$500 million from November 2017	• Debt maturity of about C$450 million over the next 12 months • Maintenance and committed capital spending of about C$500 million over the next 12 months

Group Influence

We continue to view Union as an insulated subsidiary within the Enbridge group, reflecting our view that the regulatory restriction and the parent's strategy with respect to Union will continue to preserve the utility's credit strength and are consistent with our view of insulation on a subsidiary. Specifically, the regulatory restriction limits Union's business activities and requires the utility to maintain the common equity thickness at the regulatory deemed capital structure. This restriction will prevent the subsidiary from supporting the group to the extent that it would impair its stand-alone creditworthiness. Furthermore, we expect that similar insulation features will continue through to Amalco; the potential merger with EGD was announced Nov. 2, 2017. In addition, we expect Enbridge's current strategy with respect to its regulated gas distribution utilities, including both EGD and Union, will continue through Amalco, preserving the regulated utilities' credit strength.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** bbb+
- **Entity status within group:** Insulated (no impact)

Issue Ratings

Subordination risk analysis

Capital structure

Union, the operating subsidiary, has about C$3.4 billion of senior unsecured debentures.

Analytical conclusions

Given that Union is an investment-grade regulated utility and all the senior unsecured debt is at the operating subsidiary level, we do not consider the debt structurally subordinated. As a result, we equalize the issue-level rating on the unsecured debt with our 'A-' long-term corporate credit rating on the utility.

Related Criteria

- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Criteria - Insurance - General: Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

S&P Global
Ratings

Research

Research Update:

Union Gas Ltd. Ratings Raised To 'A-' From 'BBB+' On Merger Between Parent Spectra Energy Corp. And Enbridge Inc.

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Research Update:

Union Gas Ltd. Ratings Raised To 'A-' From 'BBB+' On Merger Between Parent Spectra Energy Corp. And Enbridge Inc.

Overview

- On Feb. 27, 2017, Enbridge Inc. announced the closing of the merger with Spectra Energy Corp.
- As a result, we are raising our long-term corporate credit and senior unsecured debt ratings on Spectra subsidiary Union Gas Ltd. to 'A-' from 'BBB+'.
- We are removing the ratings from CreditWatch, where they were placed with positive implications Sept. 6, 2016.
- The upgrade solely reflects the application of our group rating methodology criteria and reflects our view that Union is a core asset and insulated subsidiary to the Enbridge group.
- The stable outlook on Union reflects our expectation that the company will continue to generate stable and predictable cash flows from its regulated gas distribution operation.

Rating Action

On Feb. 28, 2017, S&P Global Ratings raised its long-term corporate credit and senior unsecured debt ratings on Ontario-based regulated gas distributor Union Gas Ltd.to 'A-' from 'BBB+', following the closing of the merger between parent Spectra Energy Corp. and Enbridge Inc. At the same time, S&P Global Ratings raised its global scale and Canada scale preferred shares ratings on Union to 'BBB' and 'P-2', respectively, from 'BBB-' and 'P-2 (Low)', respectively, reflecting the flow-through impact of the raised corporate credit rating. S&P Global Ratings removed these ratings from CreditWatch, where they were placed with positive implications Sept. 6, 2016. The outlook is stable.

As well, S&P Global Ratings also affirmed its 'A-2' short-term rating on the company, and its 'A-2' global scale and 'A-1(Low)' Canada scale commercial paper ratings on Union.

Rationale

The upgrade follows Enbridge's announcement on the closing of the merger with Spectra. The upgrade solely reflects the application of our group rating methodology (GRM) criteria. With the transaction's close Enbridge, with 'bbb+' group credit profile (GCP), is now the ultimate parent of Union, which has a stand-alone credit profile (SACP) of 'a-'. We believe Union is a valuable asset and strategic to the Enbridge group, even if the company's cash flow contribution to the Enbridge group is very small. We believe the company's regulated gas distribution operation complements the overall group strategy of Enbridge, itself a large diversified holding company with operations in transporting crude oil and natural gas gathering, transporting, treatment and processing operations. In addition, Enbridge owns Enbridge Gas Distribution Inc. (EGD), the largest regulated gas distributor in Ontario. Union's addition will further increase Enbridge's regulated gas distribution foot print in Ontario, covering nearly the entire province.

Based on our methodology, we rarely rate a utility higher than its parent. However, for Union, there are insulation measures in place that governs the company's financial and business activities to ensure operating sustainability. Specifically, major insulation measures include a minimum equity level requirement (which can limit dividend payouts), quarterly capital structure forecasts, asset sale restrictions, and financial penalties for noncompliance. These insulation measures prevent Union from supporting the group to the extent that it would in turn unduly impair the company's stand-alone credit worthiness. More important, these will not change under Enbridge's ownership. This allows for a one-notch rating separation between Union and its parent.

The fundamentals of Union's gas distribution operation have not changed following the merger. The company continues to operate under the Ontario Energy Board (OEB) regulatory framework, which underpins its predictable and stable cash flow. The approved revenue requirement includes all operating, interest, and capital expenses and the opportunity to earn a modest return. In addition, several mechanisms support timely recovery of material and unexpected capital costs, including rate riders and (in some circumstances) the ability to request a rate-reset hearing.

Commodity costs (specifically, natural gas) remain a complete flow-through to ratepayers and are recovered through a quarterly adjustment mechanism, thereby limiting Union's exposure to commodity risk and associated cash flow volatility. Furthermore, the cap and trade carbon tax, recently introduced by the Ontario government, is also a flow-through to ratepayers and has no impact on the company's financial measures.

Enbridge now owns virtually all of Ontario's gas distribution through Union and EGD. However, these two entities will continue to operate separately in their respective service regions. In our view, Union has a diverse customer base within its service territory with a large portion of residential customers. Demand for natural gas in the residential-based customer class can change due to weather-driven changes, which expose Union to volume risk. However, the magnitude of the change does not present a rating risk, and forecasts are based on normalized weather.

Under the Ontario regulatory framework, natural gas distributors, including Union, have an obligation to ensure adequate supply of natural gas.

Previously, gas distributors in Ontario have been depending primarily on gas supply from the Western Canada Sedimentary Basin (WCSB). However, the Dawn-Parkway Expansion project allows Union to gain access to cheaper gas supply and to diversify its sources of gas supply to include the WCSB, Chicago, Dawn, and Niagara (Marcellus/Utica formations). The Dawn-Parkway project has an estimated cost of C$1.5 billion, and should be complete by the end of 2017. We expect the large capital programs will pressure credit metrics during construction period until completion, after which the capital assets become part of the rate base.

Under our base-case scenario, we project that Union's financial performance will be adequate to support the ratings, with adjusted funds from operations (AFFO)-to-debt of about 11% in 2017 before improving to 11%-12% in 2018, following the Dawn-Parkway project's completion. Debt leverage will be high, with debt-to-EBITDA of about 6x in both 2017 and 2018. Modest growth in new customers (of about 20,000 per year) should slightly offset pressure on credit metrics. The recent surge in housing prices in the Greater Toronto Area (GTA) has resulted in homeowners moving to the outskirts of the GTA and beyond. Union's service territory covers along major highways that connect to the GTA, so we expect the utility could benefit from a modest uptick in customer growth, leading to new gas distribution revenue. Our base-case scenario also incorporates capital spending of about C$800 million in 2017 and C$400 million in 2018.

Liquidity

Our view of Union's liquidity is adequate. We expect that liquidity sources will be adequate to cover uses more than 1.1x in the next 12 months. We also expect that in the event of a 10% EBITDA decline, the company's sources of funds would still exceed its uses. In our opinion, Union has sound relationships with its banks and generally prudent financial risk management. In the event of unexpected financial stress, we believe the utility would scale back on its capital expenditures and has the flexibility to suspend dividend payments to preserve the credit metrics.

Principal liquidity sources include:
- Projected FFO of C$480 million-C$500 million over the next 12 months
- Committed revolver availability of C$700 million as of September 30, 2016 expiring in 2021

Principal liquidity uses include:
- Debt maturity of about C$125 million over the next 12 months
- Capital spending of about C$800 million over the next 12 months

Outlook

The stable outlook on Union reflects our expectation that the company will continue to generate stable and predictable cash flows from its regulated gas distribution operation. We also expect Union will execute its planned capital programs on time and budget.

The outlook also reflects our outlook on parent Enbridge. The stable outlook on Enbridge reflects our expectation that the consolidated entity will continue generating stable cash flows. We also expect that Enbridge will maintain AFFO-to-debt at the low end of the significant financial risk profile category, at about 14%.

Downside scenario

Although unlikely, we could lower the rating on Union if the company experiences material operational issues, delays, and cost overruns in capital projects implementation; or adverse material regulatory decisions that lead to sustained deterioration in forecast AFFO-to-debt approaching 9% with no prospect of improvements.

Also, we could also lower the rating on Union if we lower our group credit profile (GCP) on Enbridge. This could happen if the parent's consolidated AFFO-to-debt ratio falls and stays below 11%, which could result from weaker financial performance, due to mainline volumes falling below expectations, or more aggressive funding of the large combined capital program throughout our outlook period.

Upside scenario

An upgrade to Union is unlikely without an upgrade to the Enbridge GCP, which the consolidated rating on the parent determines, in conjunction with an upgrade to the stand-alone credit profile (SACP) of Union. This is because we cap our rating on the company at the lesser of the SACP or one notch above the GCP given our assessment of the insulation measures in place that allow a one notch separation as an insulated subsidiary.

An upgrade to Union's SACP would require the company to improve financial measures with AFFO-to-debt approaching and staying at 14%, which could happen if the company's gas distribution revenue increases substantially and permanently. However, we do not expect this to happen during our outlook period given rates are regulated. An upgrade to Enbridge's GCP would require the company to improve financial measures with consolidated AFFO-to-debt above 15%-16% on a sustained basis. Given Union's relatively small cash flow contribution to the Enbridge group, improvement to the company's financial measures alone would have a negligible impact on the ratings on Enbridge.

Ratings Score Snapshot

Corporate Credit Rating: A-/Stable/A-2

Business risk: Excellent
- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant
- Cash flow/Leverage: Significant

Anchor: a-

Modifiers
- Diversification: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Financial policy: Neutral (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a-
- Group credit profile: bbb+
- Entity status within group: Insulated subsidiary (no impact)

Related Criteria

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 07, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Criteria - Insurance - General: Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Ratings List

Upgraded; Short-Term Rating Affirmed; CreditWatch/Outlook Action

	To	From
Union Gas Ltd.		
Corporate credit rating	A-/Stable/A-2	BBB+/Watch Pos/A-2

Upgraded; CreditWatch/Outlook Action

	To	From
Union Gas Ltd.		
Senior unsecured	A-	BBB+/Watch Pos
Preferred stock		
Global scale	BBB	BBB-/Watch Pos
Canada scale	P-2	P-2(Low)/Watch Pos

Ratings Affirmed

Union Gas Ltd.	
Commercial paper	
Global scale	A-2
Canada scale	A-1(Low)

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at www.spcapitaliq.com. All ratings affected by this rating action can be found on the S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 8, Schedule 1, Attachment 2 – 2021 Audited Financial Statement

Question(s):

Under Note 2 Push-Down Accounting of the audited financial statements (AFS), it states that push-down accounting with respect to the accounts of Union Gas was applied. The carrying values of certain assets and liabilities of Union Gas transferred to EGD have been adjusted to reflect Enbridge Inc.'s (Enbridge) historical cost as at February 27, 2017, the date upon which Enbridge acquired common control of EGD and Union Gas.

Furthermore, under Note 7 Property, Plant & Equipment, it states that depreciation expense is $22M in incremental depreciation resulting from push-down accounting for the year ended December 31, 2021.

a) Please discuss how the accounting of Union Gas's assets and liabilities have been treated for regulatory purposes upon acquisition of EGD and Union Gas.

b) Please confirm that the historical costs for Union Gas's capital assets were adopted for regulatory purposes. If not confirmed, please discuss and explain why the implications of this are not reflected in the Accounting Policy Change Deferral Account.

Response:

a) The treatment of Union's assets and liabilities for regulatory purposes has been status quo since the acquisition of EGD and Union by Enbridge on February 27, 2017, aside from the material items listed below that were pushed down to Enbridge Gas as of the amalgamation of EGD and Union on January 1, 2019:

   i. Long Term Debt: In accordance with ASC 805, the net assets and liabilities of Union that were acquired were re-measured to fair value – this included long-term debt. The long-term debt that was recognized in Union's financial statements was re-measured to fair value, which resulted in an increase to the carrying value of long-term debt that was recognized in UGL's financial statements. As part of the Purchase Price Discrepancy (PPA), EGI recognized a regulatory asset in the same amount to offset the fair value bump to long-term debt. This regulatory asset is drawn down (amortized) annually, offsetting the $22 million PPA noted as depreciation in Note 7 of the Audited Financial Statements. Therefore, there is no impact to the utility results for this item.

ii. Pension: ASC 805 requires the recognition of a liability for the excess of the benefit obligation over the fair value of the plan assets, both re-measured at the acquisition date using current discount rates and assumptions established by the acquirer. Enbridge recognized an adjustment to increase the pension obligation and pension assets related to Union’s defined benefit pension plan. As part of the PPA, the accumulated other comprehensive income (AOCI) of approximately $250 million that was recorded in Union’s financial records in accordance with ASC 715 was eliminated on the acquisition date. The impacts noted above were pushed down to Enbridge Gas on amalgamation of EGD and Union, and Enbridge Gas recognized a regulatory asset within the APCDA to ensure continued recognition of the unamortized balance of actuarial gains/losses and past service costs. The balance has continued to be drawn down and recognized as pension expense. Therefore, there has been no impact to the utility results for this item. Please see response at Exhibit I.4.4-STAFF-133 for a continuity of the pre-2017 losses noted here.

b) Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 8, Schedule 1, Attachment 2 – 2021 Audited Financial Statement

Question(s):

Under Note 2 Asset Retirement Obligations (ARO) of the AFS, it states that currently for the majority of assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

Under Note 19 Environmental, it states that to the extent that Enbridge Gas is unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, it will be responsible for payment of liabilities arising from environmental incidents associated with our operating activities.

a) Please clarify whether Enbridge Gas has AROs recorded in its financial statements.
   i. If yes, please explain how it is treated for regulatory purposes, where it is included in the application, and quantify the amount(s).

b) Please clarify whether Enbridge Gas has environmental liabilities recorded in its financial statements.
   i. If yes, please explain how it is treated for regulatory purposes, where it is included in the application, and quantify the amount(s).

Response:

a) Yes, Enbridge Gas has AROs recorded in its financial statements. However, the asset retirement obligations are not associated with regulated long-lived assets and therefore do not impact utility financial results.

b) No, Enbridge Gas does not have any environmental liabilities recorded in its financial statements.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Ref 1: Exhibit 1, Tab 8, Schedule 1, Attachment 2 – 2021 Audited Financial Statement (AFS)
Ref 2: EB-2012-0459, Decision with Reasons, July 17, 2014

Question(s):

In the 2021 AFSs, Note 5 shows long-term regulatory liabilities for the future removal and site restoration reserves of $1,543 million for 2021. Footnote 9 states that the amount consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates.

In the OEB's Decision for EGD's 2014-2018 Custom IR proceeding noted in Reference 2, the OEB approved the Constant Dollar Net Salvage (CDNS) method for site restoration costs (SRC). In that proceeding, EGD proposed to refund $259.8 million in excess SRC to ratepayers. The OEB decided that the refund would be increased by an additional $120 million and the SRC provision for 2014 to 2018 would be reduced by $85 million.

a) Please confirm that the $1,543 million of future removal and site restoration reserves shown in the 2021 AFS represents the amount that has been recovered from customers in rates as at December 31, 2021. If not confirmed, please explain what the amount represents.

b) Please provide the approximate amount of site restoration costs that have been recovered to date.
    i. Please confirm that this amount would be equal to the SRC provision in accumulated depreciation. If not confirmed, please explain why not.

c) On page 60 of Reference 2, it was estimated that EGD would require over $3 billion in the future to remove and replace assets at the end of their useful lives. Please provide the most current update on the estimated total future removal and replacement costs.

d) Please confirm that when SRC are incurred, actual SRC costs draw down the accumulated SRC reserve in accumulated depreciation. If not confirmed, please explain how SRC are recorded for regulatory purposes when incurred and confirm that there is no double counting of recovery of SRC.

e) In EGD's 2014 to 2018 Custom IR proceeding, the OEB required the SRC refund to be increased by an additional $120 million and the SRC provision for 2014 to 2018 to be reduced by $85 million. Please explain the implications of the OEB's decision to the SRC reserve and annual SRC provision in its 2021 AFS and for 2024 to 2028.

f) Please quantify the annual SRC provision from 2024 to 2028.
   ii. Please explain whether the annual SRC provision is equal to the SRC forecasted to be incurred from 2024 to 2028.
   iii. If the annual SRC provision is not equal to the SRC forecasted to be incurred from 2024 to 2028 are not equal, please provide the annual SRC forecasted to be incurred from 2024 to 2028.

g) When EGD was approved to transition from the Traditional method of accounting for SRC to the CDNS method in EGD's 2014 to 2018 Custom IR proceeding, the accumulated depreciation requirement (i.e. SRC reserve) was less than the requirement using the Traditional method. The difference between the two was approved to be returned to ratepayers. In the current rate application, Enbridge Gas is proposing that Union Gas transition from the Traditional Method to the CDNS method. For Union Gas, please quantify the SRC reserve under the Traditional method and the SRC reserve under the CDNS method.
   i. If there is no difference in the SRC reserve between the two methods, please explain why and how it is different from EGD's circumstances when EGD transitioned from the Traditional method to the CDNS method.
   ii. If there is a difference in the SRC reserve between the two methods, please explain the difference and Enbridge Gas's proposed treatment for the difference.

Response:

a) Not confirmed. The amount is the presumed amount recovered in rates, based on the salvage component in approved depreciation rates applied to actual gross plant values, net of actual removal and restoration costs incurred as of Dec. 31, 2021. The Company is not able to quantify the actual amount recovered in rates, which would have been based on applying approved salvage component of depreciation rates to the forecasts of gross plant, and then would have been subject to actual versus forecast customer and volumetric variances.

b) Enbridge Gas is not able to quantify the total amount of net salvage/site restoration costs it has recovered through depreciation to date, because as noted above the actual costs of removal and restoration have been netted against amounts recovered over time. Similarly, the site restoration cost provision included within accumulated depreciation reflects amounts recovered over time, net of costs incurred over time.

c) The estimated amount of future site restoration costs for all of Enbridge Gas's assets discounted to today's dollar equivalent is \$4.7 billion (\$21.3 billion undiscounted).

   The following response was prepared provided by Concentric:

   Please see response at Exhibit I.1.4.5-IGUA-14, Attachment 1 which provides the detailed CDNS calculations for each account. The currently estimated future cost of removal requirement is identified in the column "Future Salvage Requirement".

d) Confirmed.

e) The OEB's decision within EGD's custom incentive regulation (CIR) Application[1], which directed the refund of \$379.8 million in site restoration reserves to ratepayers, as compared to the proposed \$259.8, served to reduce the SRC reserve/liability reflected by the Company by \$379.8 million by the end of 2018 (or by an incremental \$120 million), as compared to what it would have been had the refund not occurred. That reduction in the reserve due to the amounts refunded carries on indefinitely, when considered discretely from any adjustments to the net salvage component of depreciation rates that are made and approved in subsequent depreciation studies. From a regulatory perspective, the reduction in the reserve increased utility rate base, as the reserve/liability is included as part of accumulated depreciation within rate base.

   With respect to the OEB's Decision which directed an \$85 million reduction to the forecast reserve amounts to be collected (through the net salvage component of depreciation rates) over the 2014 – 2018 CIR term, it has also served to reduce the SRC reserve/liability reflected by the Company, as compared to what it otherwise would have been absent the directive. In order to implement that directive, the net salvage component of the depreciation rates approved as part of that proceeding were adjusted (i.e. lowered), such that when they were applied to the forecast depreciable gross plant balances, it resulted in a cumulative \$85 million reduction in forecast depreciation expense over the 2014 to 2018 term, as compared to what it would have been based on the proposed depreciation rates. The actual reduction in the reserve that occurred over the 2014 to 2018 term would however have varied somewhat from the forecast \$85 million, as it reflected the impact of applying the

[1] EB-2012-0459.

approved depreciation rates to the actual gross plant balances that occurred over that term.

Since 2018, the annual provision for site restoration reserves, recognized as part of depreciation expense on EGD rate zone assets, continues to be lower than it otherwise would have been absent the OEB's direction. The approved depreciation rates (i.e. rates with a lower net salvage component) continue to be applied to actual depreciable gross plant balances, and will continue to be applied until such time as new depreciation rates inclusive of an updated net salvage component are approved, as are being requested within this proceeding. Therefore, as at December 31, 2021, a greater than $85 million reduction to the reserve has occurred as a result of the continued application of the OEB approved depreciation rates beyond 2018.

As of the end of 2023, the outstanding reserve amount will reflect the cumulative reduction that occurred as a result of applying the approved depreciation rates (reflecting a lower net salvage component) to actual EGD rate zone gross depreciable plant balances over the 2014 to 2023 period. Commencing in 2024 and through 2028, the annual site restoration cost provision, which will impact the outstanding reserve, will cease being directly impacted by the OEB's directive in EB-2012-0459, as it is expected that new depreciation rates, inclusive of updated net salvage components, will be approved and implemented.

f) The estimated annual SRC provision for 2023 to 2026 is shown in Table 1. Enbridge Gas is unable to provide the estimate from 2027 to 2028 due to the forecasting horizon used for planning purposes. The forecasts for 2025 and 2026 do not include the changes to depreciation expense reflected in the March 8, 2023 update. Please see response at Exhibit I.1.2-SEC-6.

Table 1

$ Million	2023	2024	2025	2026
Estimated SRC provision	$91.2	$118.6	$135.0	$141.3

i) The annual SRC provision is not equal to the SRC forecasted for 2024 to 2026. This is due to differences in the timing of the collection of the SRC vs the SRC expenditures.

ii) The annual SRC forecasted to be incurred for 2024 to 2026 is show in Table 2:

Table 2

$ Million	2023	2024	2025	2026
Forecasted SRC incurred	$61.4	$62.8	$60.5	$55.5

g) The following response was provided by Concentric:

Given the harmonization of the accounts, it is not possible to develop a theorical net salvage accumulated depreciation calculation separately for the EGD and Union assets. Furthermore, given that booked accumulated depreciation amounts related to the legacy EGD assets were based on the use of the CDNS method, it is not feasible to recalculate those balances on the assumption that a traditional method of salvage analysis had been used.

However, in order to be responsive to the question, Concentric has calculated the accumulated depreciation variance resulting from the comparison of the calculated accumulated depreciation using the CDNS method and booked accumulated depreciation amounts on the harmonized company using the actual accumulated depreciation balances. The calculation is summarized below:

Calculated accumulated depreciation (using CDNS method)	$1,197 million
Booked accumulated depreciation	$1,543 million
Surplus/(Deficiency)	$ 346 million

Enbridge Gas is proposing a remaining life depreciation calculation (as currently approved for both the EGD and Union systems). The above accumulated depreciation variance is embedded in the estimated remaining life depreciation accruals of each account in accordance with the remaining life calculations included in Section 8 of the Concentric depreciation study report.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Ref 1: Exhibit 1, Tab 8, Schedule 2, p.3
Ref 2: January 27, 2023, Evidence Corrections and Updates

Question(s):

Regarding reporting under USGAAP, Enbridge Gas stated that the Ontario Securities Commission and the Alberta Security Commission decided that Enbridge Gas can continue to use USGAAP for financial reporting purposes until January 1, 2027.

a) Please explain Enbridge Gas's views on adopting International Financial Reporting Standards (IFRS) for regulatory purposes if it is required to adopt IFRS for financial reporting purposes.

b) Please explain whether Enbridge Gas has assessed the implications of adopting IFRS. If yes, please discuss.

c) If Enbridge Gas is required to adopt IFRS during its IRM term, please discuss how Enbridge Gas will address this change for regulatory purposes (e.g. establishment of a DVA).

Response:

a) Enbridge Gas views the adoption of IFRS for regulatory purposes as appropriate upon adopting IFRS for financial reporting purposes. However, please see response at part c).

b) Enbridge Gas has not undertaken the necessary work to assess or quantify the differences between US GAAP and IFRS and any resulting implications. To understand the differences (if any), Enbridge Gas would be required to conduct a lengthy and complex assessment of the differences between US GAAP and IFRS as a whole. Enbridge Gas is aware that the International Accounting Standards Board has proposed a new rate-regulated accounting standard, which is expected to address some of the differences, however the substance of the final standard is unknown at this time.

c) If Enbridge Gas is required to adopt IFRS during its IRM term, Enbridge Gas believes that one viable option would be to establish a deferral account similar to the Accounting Policy Changes Deferral Account. However, Enbridge Gas would need to fully assess the implications for regulatory purposes at a time when the final rate-regulated IFRS standard is issued.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Ref: Exhibit 1, Tab 8, Schedule 2, p.5
Ref 2: Exhibit 1, Tab 9, Schedule 1, Attachment 1
Ref 3: Exhibit 2, Tab 6, Schedule 1, p.35

Question(s):

In Table 1, Enbridge Gas listed accounting standard updates that had no impact or an immaterial impact on its revenue requirement. Enbridge Gas indicated that the update for ASU 2017-07 Improving the Presentation of Net Periodic Benefit Cost related to Defined Benefit Plans improves the income statement presentation of the components of net periodic pension cost and net periodic post-retirement benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. OEB staff notes that the update also allows only the service cost component to be eligible for capitalization, when applicable.

Enbridge Gas also indicated that for ASU 2018-15 relating to cloud computing arrangements, the ASU specifies that an entity would apply Accounting Standards Codification 350-40, internal-use software, to determine which implementation costs related to a hosting arrangement that is a service contract should be capitalized and which should be expensed. Ref 2 shows capital expenditure integration project for the CIS Integration HANA cloud application of $11.8 million as at December 31, 2023.

a) Regarding ASU 2017-07, please confirm that the update relating to capitalization also did not have a material impact on Enbridge Gas's revenue requirement.

   i. If not confirmed, please quantify and explain the impact on the treatment of capitalization of pensions and Other Post Employment Benefits (OPEB) since the implementation of ASU 2017-07.

b) With regards to cloud computing, please explain Enbridge Gas's regulatory treatment for cloud computing and whether these costs are capitalized or expensed.

   i. Please provide a schedule showing all costs related to cloud computing as at December 31, 2023 broken down by project/category as applicable, and indicate whether each of these costs have been expensed or capitalized.

ii. Reference 3 states that Enbridge Gas has adopted cloud computing services, and that the transition to cloud computing services results in higher O&M costs (lower capital costs) as spending shifts away from capital. Please indicate which costs in response to part “b” above would have been historically treated as capital.

Response:

a) Confirmed.

b) In accordance with US GAAP, all cloud computing costs that do not pertain to implementation costs or costs related to software licenses, are expensed as incurred.

i. Cloud computing costs forecasted to be incurred in 2023 are provided at Table 1.

Table 1
2023 Cloud Computing Costs

Category ($ millions)	Expensed (a)	Capitalized (b)
New Capabilities	7.9	10.7
Shifted to Cloud	9.7	10.1
Totals	17.6	20.8

ii. The services related to the expenses in column (a) of the table would have been historically treated as capital. However, the traditional on-premise solution is not a one to one comparison with the cloud computing services expensed in column (a). The capital associated with an on-premise solution would be significantly higher. Therefore, the costs associated with the two methods are not a one to one comparison.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 8, Schedule 1, Attachment 4, p1

Question(s):

In the above reference noted, there is an adjustment to corporate income to derive utility income. Specifically, there is an adjustment of $4.4 million to gas sales and distribution, and gas costs as well as an adjustment of $0.4 million to transportation revenues. These adjustments relate to accelerated CCA.

Please elaborate further on the $4.4 Million and $0.4 Million accelerated CCA adjustments and explain why they would impact the revenues and costs of the utility.

Response:

The adjustments of $4.4 million to increase 2019 utility gas sales and distribution revenue, and $0.4 million to increase 2019 utility transportation revenues, were to eliminate 2018 accelerated CCA impacts related to EGD and Union that were recorded in 2019, but previously reflected in the 2018 utility results for each utility. As the enactment of Bill C-97, which enabled accelerated CCA, occurred in June 2019 but was effective in respect of capital expenditures made and placed into service on or after November 21, 2018, the impact related to applicable 2018 capital additions could not be recognized/accounted for within corporate accounting results until 2019. However, the 2018 utility results for each of EGD and Union, which were filed after the enactment of Bill C-97[1], incorporated the 2018 impacts of accelerated CCA. Within the 2018 results, revenues were reduced/debited, with a corresponding payable reflected in the Tax Variance Deferral Account, to eliminate the revenue requirement impact of accelerated CCA that was reflected in the 2018 utility income tax calculations. As the reduction in revenues was reflected in 2018 utility results, but recorded in 2019 corporate results, the reductions needed to be reversed/eliminated from the determination of 2019 utility results to ensure they were not double counted from a utility perspective.

[1] EB-2019-0105.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 9, Schedule 1, p. 16

Question(s):

The OEB approved the amalgamation of EGD and Union Gas in EB-2017-0306/0307. As part of its decision on the amalgamation, the OEB also approved a ratemaking framework and a deferred rebasing period of 5 years. In order to deliver the integration benefits and the savings to be passed on to customers at rebasing, O&M costs associated with integration were tracked separately over the deferred rebasing term. Enbridge Gas has noted that these costs will no longer be required beyond 2023 and were not reflected in rates during the deferred rebasing term, and as such were borne by the utility. Also included are severance costs associated with any full-time equivalent (FTE) reductions brought about by restructuring.

a) Please confirm that integration costs incurred by Enbridge Gas or forecast to be incurred are not included in the 2024 OM&A costs.

b) Please confirm if Enbridge Gas has included any severance costs associated with FTE reductions brought about by restructuring in 2024 O&M costs or in the 2024 revenue requirement. Also, please provide any severance costs included in 2024 rates.

Response:

a) Confirmed. O&M integration costs are not included in the 2024 Test Year Forecast.

b) Confirmed, there are no severance costs related to integration restructuring in 2024 O&M costs or in the 2024 revenue requirement. Enbridge Gas has included $1.6 million in regular recurring severance charges within the 2024 Test Year Forecast for Central Functions Allocations.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 1, Tab 8, Schedule 1, Attachment 10

Question(s):

a) Please provide EGI's 2022 Annual Report once it becomes available.

Response:

a) Exhibit 1, Tab 8, Schedule 1, Attachment 10 contains Enbridge Inc.'s (Enbridge Gas's ultimate parent company) 2021 Annual Report. Enbridge Gas does not produce an Annual Report. Enbridge Gas interprets this question to be asking for Enbridge Inc.'s 2022 Annual Report.

   At the time of responding to this question, Enbridge Inc.'s 2022 Annual Report was not yet available. However, since Enbridge Inc.'s Annual Report typically consists of a letter to shareholders followed by its Form 10-K, a copy of Enbridge Inc.'s 2022 Form 10-K is provided at Attachment 1.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2022
or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to
Commission file number 001-15254

ENBRIDGE INC.
(Exact Name of Registrant as Specified in Its Charter)

Canada	**98-0377957**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

200, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
(Address of Principal Executive Offices) (Zip Code)
Registrant's telephone number, including area code **(403) 231-3900**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Shares	ENB	New York Stock Exchange
6.375% Fixed-to-Floating Rate Subordinated Notes Series 2018-B due 2078	ENBA	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☒	Accelerated Filer	☐
Non-Accelerated Filer	☐	Smaller reporting company	☐
Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. Yes ☒ No ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to § 240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the registrant's common shares held by non-affiliates computed by reference to the price at which the common equity was last sold on June 30, 2022, was approximately US$85.6 billion.

As at February 3, 2023, the registrant had 2,024,907,965 common shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
Not applicable.

EXPLANATORY NOTE

Enbridge Inc., a corporation existing under the *Canada Business Corporations Act*, qualifies as a foreign private issuer in the United States (US) for purposes of the *Securities Exchange Act of 1934, as amended* (the Exchange Act). Although, as a foreign private issuer, Enbridge Inc. is not required to do so, Enbridge Inc. currently files annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K with the Securities and Exchange Commission (SEC) instead of filing the reporting forms available to foreign private issuers.

Enbridge Inc. intends to prepare and file a management proxy circular and related material under Canadian requirements. As Enbridge Inc.'s management proxy circular is not filed pursuant to Regulation 14A, Enbridge Inc. may not incorporate by reference information required by Part III of this Form 10-K from its management proxy circular. Accordingly, in reliance upon and as permitted by Instruction G(3) to Form 10-K, Enbridge Inc. will be filing an amendment to this Form 10-K containing the Part III information no later than 120 days after the end of the fiscal year covered by this Form 10-K.

GLOSSARY

AFUDC	Allowance for funds used during construction
Aii	Athabasca Indigenous Investments Limited Partnership
AOCI	Accumulated other comprehensive income/(loss)
ARO	Asset retirement obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Aux Sable	US Midstream ownership interest in Aux Sable Liquid Products LP, Aux Sable Midstream LLC, Aux Sable Canada LP
BC	British Columbia
bcf/d	Billion cubic feet per day
the Board	Board of Directors
Cactus II	Cactus II Pipeline, LLC
CER	Canada Energy Regulator, created by the Canadian Energy Regulator Act which also repealed the National Energy Board Act, on August 28, 2019
CTS	Competitive Toll Settlement
DAPL	Dakota Access Pipeline
Dawn	An extensive network of underground storage pools at the Tecumseh Gas Storage facility and Dawn Hub
DCP	DCP Midstream, LP
EBITDA	Earnings before interest, income taxes and depreciation and amortization
EEP	Enbridge Energy Partners, L.P.
EIEC	Enbridge Ingleside Energy Center
EIS	Environmental Impact Statement
Enbridge Gas	Enbridge Gas Inc.
EPS	Emission Performance Standards
ESG	Environment, Social and Governance
Exchange Act	United States Securities Exchange Act of 1934
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
Gray Oak	Gray Oak Pipeline, LLC
H2	Hydrogen gas
IJT	International Joint Tariff
IR	Incentive Regulation
kbpd	Thousand barrels per day
L3R	Line 3 Replacement
LMCI	Land Matters Consultation Initiative
LNG	Liquefied natural gas
Magic Valley	Magic Valley Wind Farm
M&N	Maritimes & Northeast Pipeline

M&N Canada	Canadian portion of our Maritimes & Northeast Pipeline
the Court	United States District Court for the Western District of Wisconsin
MD&A	Management's Discussion and Analysis
MW	Megawatts
NCIB	Normal course issuer bid
NEXUS	NEXUS Gas Transmission Pipeline
NGL	Natural gas liquids
Noverco	Noverco Inc.
NYSE	New York Stock Exchange
OBPS	Output-based pricing system
OCI	Other comprehensive income/(loss)
OEB	Ontario Energy Board
OPEB	Other postretirement benefit obligations
P66	Phillips 66
the Partnerships	Spectra Energy Partners, LP and Energy Energy Partners, L.P
PennEast	PennEast Pipeline Company, L.L.C.
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPA	Power purchase agreement
PSU	Performance Stock Units
the Reservation	Bad River Reservation
RNG	Renewable natural gas
ROE	Return on equity
ROU	Right-of-use
RSU	Restricted Stock Units
SEC	US Securities and Exchange Commission
SEP	Spectra Energy Partners, LP
SESH	Southeast Supply Header, L.L.C.
Spectra Energy	Spectra Energy Corp
Texas Eastern	Texas Eastern Transmission, L.P.
TGE	Tri Global Energy, LLC
TSX	Toronto Stock Exchange
UK	The United Kingdom
US	United States of America
US GAAP	Generally accepted accounting principles in the United States of America
Vector	Vector Pipeline L.P.
VIEs	Variable interest entities
Westcoast	Westcoast Energy Inc.
Woodfibre	Woodfibre LNG Limited Partnership

CONVENTIONS

The terms "we", "our", "us" and "Enbridge" as used in this report refer collectively to Enbridge Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge.

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars, all references to "dollars" or "$" are to Canadian dollars and all references to "US$" are to US dollars. All amounts are provided on a before-tax basis, unless otherwise stated.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this Annual Report on Form 10-K to provide information about us and our subsidiaries and affiliates, including management's assessment of our and our subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "believe", "estimate", "expect", "forecast", "intend", "likely", "plan", "project", "target" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: our corporate vision and strategy, including strategic priorities and enablers; expected supply of, demand for, exports of and prices of crude oil, natural gas, natural gas liquids (NGL), liquified natural gas (LNG) and renewable energy; energy transition and lower-carbon energy, and our approach thereto; environmental, social and governance (ESG) goals, practices and performance; industry and market conditions; anticipated utilization of our assets; dividend growth and payout policy; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected strategic priorities and performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation and Energy Services businesses; expected costs, benefits and in-service dates related to announced projects and projects under construction; expected capital expenditures; investable capacity and capital allocation priorities; share repurchases under our normal course issuer bid; expected equity funding requirements for our commercially secured growth program; expected future growth, development and expansion opportunities; expected optimization and efficiency opportunities; expectations about our joint venture partners' ability to complete and finance projects under construction; expected closing of acquisitions and dispositions and the timing thereof; expected benefits of transactions; expected future actions of regulators and courts, and the timing and impact thereof; toll and rate cases discussions and proceedings and anticipated timeline and impact therefrom, including Mainline Contracting and those relating to the Gas Transmission and Midstream and Gas Distribution and Storage businesses; operational, industry, regulatory, climate change and other risks associated with our businesses; and our assessment of the potential impact of the various risk factors identified herein.

Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of, demand for, export of and prices of crude oil, natural gas, NGL, LNG and renewable energy; anticipated utilization of assets; exchange rates; inflation; interest rates; the COVID-19 pandemic and the duration and impact thereof; availability and price of labor and construction materials; the stability of our supply chain; operational reliability; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the timing and closing of acquisitions and dispositions; the realization of anticipated benefits of transactions; governmental legislation; litigation; estimated future dividends and impact of our dividend policy on our future cash flows; our credit ratings; capital project funding; hedging program; expected earnings before interest, income taxes, and depreciation and amortization (EBITDA); expected earnings/(loss); expected future cash flows; and expected distributable cash flow. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL, LNG and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation and interest rates and the COVID-19 pandemic impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. The most relevant assumptions associated with forward-looking statements regarding announced projects and projects *under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labor and construction materials; the stability of our supply chain; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather and customer, government, court and regulatory approvals on construction and in-service schedules and cost recovery regimes; and the COVID-19 pandemic and the duration and impact thereof.*

Our forward-looking statements are subject to risks and uncertainties pertaining to the successful execution of our strategic priorities, operating performance; legislative and regulatory parameters; litigation; acquisitions, dispositions and other transactions and the realization of anticipated benefits therefrom; operational dependence on third parties; dividend policy; project approval and support; renewals of rights-of-way; weather; economic and competitive conditions; public opinion; changes in tax laws and tax rates; exchange rates; inflation; interest rates; commodity prices; access to and cost of capital; political decisions; global geopolitical conditions; the supply of, demand for and prices of commodities and other alternative energy; and the COVID-19 pandemic, including but not limited to, those risks and uncertainties discussed in this Annual Report on Form 10-K and in our other filings with Canadian and US securities regulators. The impact of any one assumption, risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and our future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statement made in this Annual Report on Form 10-K or otherwise, whether as a result of new information, future events or otherwise. All forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP AND OTHER FINANCIAL MEASURES

Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations *(MD&A) in this Annual Report on Form 10-K makes reference to non-GAAP and other financial measures, including EBITDA. EBITDA is defined as earnings before interest, income taxes and depreciation and amortization. Management uses EBITDA to assess performance of Enbridge and to set targets. Management believes the presentation of EBITDA gives useful information to investors as it provides increased transparency and insight into the performance of Enbridge.*

The non-GAAP and other financial measures are not measures that have a standardized meaning prescribed by the accounting principles generally accepted in the United States of America (US GAAP) and are not US GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers. A reconciliation of historical non-GAAP and other financial measures to the most directly comparable GAAP measures is set out in this MD&A and is available on our website. Additional information on non-GAAP and other financial measures may be found on our website, www.sedar.com or www.sec.gov.

PART I

ITEM 1. BUSINESS

Enbridge is a leading North American energy infrastructure company. Our core businesses include Liquids Pipelines, which consists of pipelines and terminals in Canada and the US that transport and export various grades of crude oil and other liquid hydrocarbons; Gas Transmission and Midstream, which consists of investments in natural gas pipelines and gathering and processing facilities in Canada and the US; Gas Distribution and Storage, which consists of natural gas utility operations that serve residential, commercial and industrial customers in Ontario and Québec; and Renewable Power Generation, which consists primarily of investments in wind and solar assets, as well as geothermal, waste heat recovery and transmission assets, in North America and Europe.

Enbridge is a public company, with common shares that trade on the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) under the symbol ENB. We were incorporated on April 13, 1970 under the Companies Ordinance of the Northwest Territories and were continued under the Canada Business Corporations Act on December 15, 1987.

A more detailed description of each of our businesses and underlying assets is provided below under *Business Segments*.

CORPORATE VISION AND STRATEGY

VISION

Our primary purpose as a company is to fuel people's quality of life in a safe, clean, and socially responsible manner. Our vision to be the leading energy infrastructure company in North America and beyond supports this purpose. In pursuing this vision, we seek to play a critical role in enabling the economic and social well-being of people across the world by providing access to affordable, reliable, and secure energy. Our infrastructure franchises transport, distribute, and generate energy, including liquids, natural gas, renewable power, and lower-carbon fuels. We recognize that the energy system is changing, and we aim to bridge to a cleaner energy future by investing in lower-carbon platforms while ensuring the continuity and stability that the world requires through the transition.

Our investor value proposition is founded on our ability to deliver predictable cash flows and a growing stream of dividends year-over-year through investment in, and efficient operation of, energy infrastructure assets that are strategically positioned between key supply basins and strong demand-pull markets. Our assets are underpinned by long-term contracts, regulated cost-of-service tolling frameworks, power purchase agreements (PPAs), and other low-risk commercial arrangements.

In addition, we strive to be a leader in worker and public safety, ESG, stakeholder relations, customer service, community investment, and employee engagement and satisfaction.

STRATEGY

Our strategy is underpinned by a deep understanding of energy supply and demand fundamentals. Through disciplined capital allocation that is aligned with our outlook on energy markets, we have become an industry leader with a diversified portfolio across both conventional and lower-carbon energies. Our assets have reliably generated low-risk, resilient cash flows through many commodity and economic cycles.

In order to continue to be an industry leader and value creator going forward, we maintain a robust strategic planning approach. We regularly conduct scenario and resiliency analysis on both our assets and business strategy. We test various value enhancement and maximization options, and we regularly engage with our Board of Directors (the Board) to ensure alignment and maintain active oversight, including updates and discussions throughout the year and a dedicated annual Strategic Planning session. Going forward, we plan to use this comprehensive approach to guide our investment and portfolio decisions.

Predictable growth is a hallmark of our investor value proposition. Our robust portfolio of project development opportunities and ongoing efficiency improvements should help drive mid-single digit growth in our distributable cash flow per share for years to come. We remain confident in our two-pronged growth strategy and expect to selectively invest in our diversified footprint of both conventional businesses and complementary lower-carbon platforms, such as renewables, Carbon Capture and Storage (CCS), Hydrogen (H2), and Renewable Natural Gas (RNG). Additionally, ESG continues to be integral to our strategy; we are committed to reducing our emissions, building lasting relationships with our stakeholders, and promoting diversity, equity, and inclusion.

In alignment with our strategy, we progressed several of our priorities in 2022. For example:

- Our Liquids Pipelines business delivered record Mainline volumes, increased ownership in and operatorship of the Gray Oak pipeline, and permitted a 2 million barrels (mmbl) storage expansion at Enbridge Ingleside Energy Center (EIEC), further bolstering our presence in the US Gulf Coast and global export markets.

- Our Gas Transmission and Midstream business successfully expanded our secured capital program notably with the T-South Expansion Program and T-North Expansion Program and acquired an equity stake in Woodfibre LNG Limited Partnership to capitalize on increasing global gas demand and supporting coal-to-gas conversions that are expected to help lower global energy emissions.

- Our Gas Distribution and Storage business added over 45,000 new customers, filed the rate rebasing application for 2024-2028 which proposes continuation of Incentive Rate-setting mechanisms, completed the Pathways to Net-Zero Emissions Study for Ontario, and progressed construction of three RNG projects and development of a green hydrogen blending project at Gazifère Inc. (Gazifère), a wholly-owned natural gas distribution company in Québec.

- Our Renewable Power Generation business accelerated its growth strategy with the acquisition of the renewable developer Tri Global Energy, LLC (TGE), securing 3.9 gigawatts (GW) of conditionally sold renewable generation projects and an additional 3 GW in development projects. In addition, the 480 megawatts (MW) Saint-Nazaire project, France’s first commercial-scale offshore wind in which Enbridge holds a stake, became fully operational in 2022. We are continuing to advance construction of three additional offshore wind projects in Europe.

- Our New Energy Technologies team, in collaboration with all of our business units, advanced our lower-carbon strategy, including building strategic partnerships to progress the Wabamun Carbon Hub in Alberta and lower-carbon hydrogen and ammonia production and export facilities in the US Gulf Coast.

- We have made meaningful progress towards our ESG goals, advancing construction of ten solar self-power projects, signing a landmark sale of a non-operating interest in pipelines in our Regional Oil Sands System to 23 Indigenous communities, and publishing our Indigenous Reconciliation Action Plan to further our engagement.

- We continue to recycle capital at attractive valuations, further optimizing and diversifying our portfolio. In addition, we are focused on improving efficiencies to increase our profitability and competitiveness.

These achievements are discussed in further detail in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.*

Looking ahead, our near-term strategic priorities remain similar to years past. As always, proactively advancing the safety of our assets, protecting the environment, and maintaining reliability of our system remain our top priorities. We are focused on enhancing the value of our existing assets, capitalizing on our extensive infrastructure, prioritizing in-franchise organic growth and export-driven opportunities, and developing lower-carbon platforms across all our businesses. We will continue to invest where we can advance our strategy, build sustainable competitive advantage, and achieve attractive risk-adjusted returns.

Our key strategic priorities include:

Safety and Operational Reliability
Safety and operational reliability are the foundation of our strategy. We strive to achieve and maintain industry leadership in all facets of safety - process, public, and personal - and ensure the highest standards of reliability and integrity across our system to protect our communities and the environment.

Extend Growth
The cornerstone of our growth lies in the successful execution of our slate of secured projects (currently $18 billion through 2028) on schedule and at the lowest practical cost, while maintaining the highest standards for safety, quality, customer satisfaction, and environmental and regulatory compliance. For a discussion of our current portfolio of capital projects refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects*.

Beyond that, we seek to continually identify additional high-quality growth opportunities across all our platforms. We expect to have sufficient equity self-funding capacity of about $5 to $6 billion per year to invest in growth without issuing any additional common equity and maintaining key credit metrics. We will remain disciplined and will strive to deploy capital towards the best uses, prioritizing balance sheet strength, investment in low capital intensity growth, and regulated utility or utility-like projects. We will carefully assess our remaining investable capacity, deploying capital to what we believe are the most value-enhancing opportunities available to us, including further organic growth, complementary accretive "tuck-in" acquisitions that improve our competitive positioning, share repurchases, or further deleveraging of our balance sheet.

Looking ahead, we see strong utilization of our existing network and opportunities for future growth within each of our businesses. For example, we expect that:

- Our liquids pipelines infrastructure will remain a vital connection between key supply basins and demand-pull markets such as the refinery hubs in the US Midwest, eastern Canada, and the US Gulf Coast. The emergence of CCS offers the potential to provide new growth opportunities over the long term.

- Our natural gas transmission business will seek extension and expansion opportunities driven by new load demand from gas-fired power generation, industrial growth, and coastal LNG plants. Looking forward, blending RNG and H2 production into our system should enhance asset longevity and enable us to offer a differentiated lower-carbon solution to customers.

- Our gas distribution and storage business will continue to grow through productivity enhancements, modernization investments, and facilities that blend H2 and RNG into the gas supply. We expect to continue to add customers over the next regulatory framework period to 2028. Additionally, we expect to expand our offerings to customers, including additional demand-side management, as well as resiliency and hybrid heating programs.

- Our enhanced renewable power capabilities position us well to capitalize on strong renewables growth in Europe and North America and execute on our large development program. We also plan to continue to progress our multi-year self-power program across our liquids and gas systems.

In addition, we aim to drive growth through an ongoing focus on optimization, modernization, productivity, and efficiency across all our businesses. Examples include: the application of drag-reducing agents and pump station modifications to optimize throughput on our liquids system, the execution of toll settlements and rate case filings to optimize revenue within our gas transmission franchises, the expansion of lower-carbon offerings to utility customers and investments in lower-carbon supply connections to the gas grid, and more generally, the creation of sustainable cost savings across the organization through innovation, process improvement and/or system enhancements.

Maintain a Strong Balance Sheet
The maintenance of our balance sheet strength is critical to our strategy. Our financing strategies are designed to retain strong, investment-grade credit ratings to ensure we have the financial capacity to meet our capital funding needs and the flexibility to manage capital market disruptions. Our current secured capital program can be readily financed through internally generated cash flow and available balance sheet capacity without issuance of additional common equity. We will seek to secure new growth within our "self-funded" equity model. In addition, we continue to look at opportunities to monetize non-core assets at attractive valuations. For further discussion on our financing strategies refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources*.

Disciplined Capital Allocation
We assess the latest fundamental trends, monitor the business landscape, and proactively conduct business development activities with the goal of identifying an industry-leading capital deployment opportunity set. We screen, analyze, and assess opportunities using a disciplined investment framework with the objective of effectively deploying capital to grow while achieving attractive risk-adjusted returns, within our low-risk "utility-like" business model.

All investment opportunities are evaluated based on their potential to advance our strategy, mitigate risks, support our ESG goals, and create additional financial flexibility. Our primary emphasis in the near term is on low capital intensity opportunities to enhance returns in existing businesses (organic expansions and optimizations), modernization of our systems, and utility rate-based investments. We also remain focused on larger projects where commercial constructs fit our investor value proposition and where we can effectively manage risks during the execution phase. In addition, we continue to assess other value-enhancing opportunities, such as accretive acquisitions that can complement our portfolio.

In evaluating typical investment opportunities, we also consider other potential capital allocation alternatives. Other alternatives for capital deployment depend on our current outlook and include further dividend increases, further debt reduction, and/or share repurchases.

Lead in Energy Transition Over Time
As the global population grows and standards of living continue to improve around the world, we expect energy demand to rise. At the same time, we, and our society, increasingly recognize the need for secure and reliable energy while reducing global greenhouse gas (GHG) emissions. Accordingly, energy systems around the world are being reshaped as industry participants, regulators, and consumers seek to lower emissions. As a diversified energy infrastructure company, we believe we are well positioned to play a key role in the energy transition by leading the development of the future energy systems with regulators and policy makers and partnering with customers on their lower-carbon strategies, while reducing our own carbon footprint.

We believe that diversification and innovation will play a significant role in the transition to a lower-carbon future. To date, we have made large investments in natural gas infrastructure and renewable energy assets, helping to decrease our emissions and further expand our platforms to enable energy transition across the globe. Our focus areas in renewable energy remain in offshore wind, utility-scale onshore projects, and integrated clean-energy offerings and solutions for customers. We are also taking a leadership role in other lower-carbon platforms like CCS, H2 and RNG where we can leverage our infrastructure, capabilities, and stakeholder relationships to accelerate growth and extend the value of our existing assets. Additionally, our new investments are expected to have a clear path to achieve net-zero emissions, in alignment with our ESG goals.

We work closely with our customers to maintain a pulse on the pace of the energy transition and are actively leveraging our ESG leadership and world-class execution capabilities to advance our positioning as a differentiated energy provider. We regularly test our assets under various transition scenarios to assess resiliency of our business.

STRATEGIC ENABLERS

Our commitment and progress on ESG, the capabilities and skills of our people, and how we utilize technology are core to executing our strategy and maintaining our competitive advantages.

Environmental, Social and Governance

Sustainability is integral to our ability to deliver energy in a safe and reliable manner. How well we perform as a steward of our environment; as a safe operator of essential energy infrastructure; as a diverse and inclusive employer; and as a responsible corporate citizen is inextricably linked to our ability to achieve our strategic priorities and create long-term value for all our stakeholders.

In 2022, we published our 21st annual Sustainability Report outlining our progress against our ESG goals[1]. In particular, we:

- Made meaningful progress towards our interim emissions intensity and net-zero GHG emissions goals through modernization and innovation of our system, efficiency improvements, and continued investment in solar self-power;
- Enhanced our efforts to ensure that our workforce and Board better reflect the diversity of our communities, empowering our workforce through employee resource groups and advancing on our diversity, equity, and inclusion commitments; and
- Continued to drive improvements towards our goal of zero safety incidents and injuries and progressed implementation of robust cyber defense programs.

Since setting our ESG targets in 2020, we have made considerable progress integrating sustainability into our strategy, governance, operations, and decision-making. We have linked ESG performance to incentive compensation and are making meaningful progress towards these targets by executing on our action plans.

1 *All percentages or specific goals regarding inclusion, diversity, equity and accessibility are aspirational goals which we intend to achieve in a manner compliant with state, local, provincial and federal law, including, but not limited to, US federal regulations, Equal Employment Opportunity Commission, Department of Labor and Office of Federal Contract Compliance Programs.*

At Enbridge, we aim to continuously strengthen our ESG approach and are undertaking the following additional actions:

- Proactively working with organizations advancing science-based guidelines for the midstream sector;
- Collaborating with key suppliers on emissions reduction plans; and
- Further developing lower-carbon energy partnerships to drive innovation across our businesses, with a focus on renewable power, RNG, H2 and CCS.

People
Our employees are essential to our success and our focus remains on enhancing the capabilities and skills of our people. We are evolving our people strategy to ensure we attract and retain the talent and leadership needed for today and tomorrow. This includes growing our focus on learning and development, and additional focus on overall well-being. We value diversity, and diverse thought, and have embedded inclusive practices in our programs, processes, and approach to people management. Furthermore, we strive to maintain industry competitive compensation, flexibility, and retention programs that provide both short- and long-term performance incentives.

Technology
We recognize the vital role technology plays in helping us achieve our strategic objectives. We are committed to pursuing innovation and technology solutions that further our safety and reliability, maximize revenues, improve efficiencies, and enable transition to new, cleaner energy solutions. We continue to strive to be on the leading edge of cyber security, by enhancing our capabilities and educating our workforce to protect our critical infrastructure system from increasing threats.

Our two Technology and Innovation labs, located in Calgary and Houston, embody our commitment to technology enabled business solutions and how we strive to entrench technology in our everyday operations.

We provide annual progress updates in our annual Sustainability Report which can be found at https://www.enbridge.com/sustainability-reports. ***Unless otherwise specifically stated, none of the information contained on, or connected to, the Enbridge website, including our annual Sustainability Report, is incorporated by reference in, or otherwise part of, this Annual Report on Form 10-K***.

BUSINESS SEGMENTS

Our activities are carried out through five business segments: Liquids Pipelines; Gas Transmission and Midstream; Gas Distribution and Storage; Renewable Power Generation; and Energy Services, as discussed below.

LIQUIDS PIPELINES

Liquids Pipelines consists of pipelines and terminals in Canada and the US that transport and export various grades of crude oil and other liquid hydrocarbons.

MAINLINE SYSTEM

The Mainline System is comprised of the Canadian Mainline and the Lakehead System. The Canadian Mainline is a common carrier pipeline system which transports various grades of crude oil and other liquid hydrocarbons within western Canada and from western Canada to the Canada/US border near Gretna, Manitoba and Neche, North Dakota and from the US/Canada border near Port Huron, Michigan and Sarnia, Ontario to eastern Canada and the northeastern US. The Canadian Mainline includes six adjacent pipelines with a combined operating capacity of approximately 3.1 million barrels per day (mmbpd) that connect with the Lakehead System at the Canada/US border, as well as five pipelines that deliver crude oil and refined products into eastern Canada and the northeastern US. Through our predecessors, we have operated, and frequently expanded, the Canadian Mainline since 1949. The Lakehead System is the portion of the Mainline System in the US. It is an interstate common carrier pipeline system regulated by the Federal Energy Regulatory Commission (FERC) and is the primary transporter of crude oil and liquid petroleum from western Canada to the US.

Tolling Framework

The Competitive Toll Settlement (CTS) which governed tolls paid for products shipped on the Canadian Mainline, with the exception of Lines 8 and 9 which are tolled on a separate basis, expired on June 30, 2021. The CTS was a 10-year negotiated agreement and provided for a Canadian Local Toll (CLT) for deliveries within western Canada, as well as an International Joint Tariff (IJT) for crude oil shipments originating in western Canada, on the Canadian Mainline, and delivered into the US, via the Lakehead System, and into eastern Canada. The IJT tolls were denominated in US dollars.

On December 19, 2019, we submitted an application to the Canada Energy Regulator (CER) to implement contracting on our Canadian Mainline System. On November 26, 2021, the CER denied the application on the basis that, among other things, contracting as proposed would result in a significant change to access on the Canadian Mainline and potentially inequitable outcomes to some shippers and non-shippers without a compelling justification.

Effective July 1, 2021, the Mainline System is on Interim Tolls which will remain in effect until new tolls are approved by the CER. In accordance with the terms of the CTS, Interim Tolls are equal to the CTS exit tolls on June 30, 2021 and are subject to finalization and adjustment applicable to the interim period, if any. We are currently exploring, with customers and other stakeholders, alternatives that may include: a modified and extended CTS, a new incentive rate-making agreement, or a cost-of-service rate-making structure. Any negotiated settlement would require CER approval before implementation. New tolling framework clarity is expected in 2023.

Shippers continue to nominate volumes on a monthly basis and we continue to allocate capacity to maximize the efficiency of the Mainline System.

Local tolls for service on the Lakehead System are not affected by Interim Tolls and continue to be established pursuant to the Lakehead System’s existing toll agreements. Under Interim Tolls, the Canadian Mainline’s share of the toll relating to pipeline transportation of a batch from any western Canada receipt point to the US border is equal to the toll applicable to that batch’s US delivery point, which is comprised of the IJT Benchmark Toll, the CTS Surcharges and the Line 3 Replacement IJT Surcharge, less the Lakehead System’s local toll to that delivery point. While on Interim Tolls, we will continue to refer to this amount as the Canadian Mainline IJT Residual Toll which is denominated in US dollars.

Lakehead System Local Tolls

Transportation rates are governed by the FERC for deliveries from the Canada/US border near Neche, North Dakota, Clearbrook, Minnesota and other points to principal delivery points on the Lakehead System. The Lakehead System periodically adjusts these transportation rates as allowed under the FERC's index methodology and tariff agreements, the main components of which are index rates and the Facilities Surcharge Mechanism. Index rates, the base portion of the transportation rates for the Lakehead System, are subject to an annual inflationary adjustment which cannot exceed established ceiling rates as approved by the FERC. The Facilities Surcharge Mechanism allows the Lakehead System to recover costs associated with certain shipper-requested projects through an incremental surcharge in addition to the existing base rates and is subject to annual adjustment on April 1 of each year. To the extent that the Lakehead System transportation rates materially under-recover the Lakehead System cost of service, an application can be made with the FERC to seek approval to increase the rates in order to bring recoveries in-line with costs.

On May 21, 2021, we filed a cost-of-service application to raise our base rates effective July 1, 2021. On June 30, 2021, the FERC issued an order to accept the rates subject to refund. This matter is currently in the FERC settlement process.

REGIONAL OIL SANDS SYSTEM

The Regional Oil Sands System includes five intra-Alberta long-haul pipelines: the Athabasca Pipeline, Waupisoo Pipeline, Woodland Pipeline, Wood Buffalo Extension/Athabasca Twin pipeline system and the Norlite Pipeline System (Norlite), as well as two large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta and the Cheecham Terminal, located south of Fort McMurray, Alberta. The Regional Oil Sands System also includes numerous laterals and related facilities which currently provide access for oil sands production from twelve producing oil sands projects.

The combined capacity of the intra-Alberta long-haul pipelines is approximately 1,090 thousand barrels per day (kbpd) to Edmonton and 1,370 kbpd into Hardisty, with Norlite providing approximately 218 kbpd of diluent capacity into the Fort McMurray region. We have a 50% interest in the Woodland Pipeline and a 70% interest in Norlite. The Regional Oil Sands System is anchored by long-term agreements with multiple oil sands producers that provide cash flow stability and also include provisions for the recovery of some of the operating costs of this system.

On October 5, 2022, we completed a transaction with Athabasca Indigenous Investments Limited Partnership (Aii), a newly created entity representing 23 First Nation and Metis communities, pursuant to which Aii acquired an 11.6% non-operating interest in seven Regional Oil Sands pipelines in the Regional Oil Sands System. Pipelines included in the transaction are the Athabasca Pipeline, Wood Buffalo Extension/Athabasca Twin pipeline system and associated tanks, Norlite, Waupisoo Pipeline, Wood Buffalo Pipeline, Woodland Pipeline, and Woodland Extension.

GULF COAST AND MID-CONTINENT

Gulf Coast includes Seaway Crude Pipeline System (Seaway Pipeline), Flanagan South Pipeline (Flanagan South), Spearhead Pipeline, Gray Oak Pipeline and the EIEC, as well as the Mid-Continent System (Cushing Terminal).

We have a 50% interest in the 1,078 kilometer (670 mile) Seaway Pipeline, including the 805 kilometer (500 mile), 30-inch diameter long-haul system between Cushing, Oklahoma and Freeport, Texas, as well as the Texas City Terminal and Distribution System which serve refineries in the Houston and Texas City areas. Total aggregate capacity on the Seaway Pipeline system is approximately 950 kbpd. Seaway Pipeline also includes 8.8 million barrels of crude oil storage tank capacity on the Texas Gulf Coast.

Flanagan South is a 950 kilometer (590 mile), 36-inch diameter interstate crude oil pipeline that originates at our terminal at Flanagan, Illinois, a delivery point on the Lakehead System, and terminates in Cushing, Oklahoma. Flanagan South has a capacity of approximately 660 kbpd.

Spearhead Pipeline is a long-haul pipeline that delivers crude oil from Flanagan, Illinois, a delivery point on the Lakehead System, to Cushing, Oklahoma. The Spearhead pipeline has a capacity of approximately 193 kbpd.

The Gray Oak pipeline is a 1,368 kilometer (850 mile) crude oil system, which runs from the Permian Basin in West Texas to the US Gulf Coast. The Gray Oak pipeline has an expected average annual capacity of 900 kbpd and transports light crude oil. As of August 17, 2022, our effective economic interest in Gray Oak increased to 58.5% from 22.8% as a result of a joint venture merger transaction with Phillips 66 (P66) and we will be assuming operatorship of Gray Oak in the second quarter of 2023.

The Mid-Continent System is comprised of storage terminals at Cushing, Oklahoma (Cushing Terminal), consisting of over 110 individual storage tanks ranging in size from 78 to 570 thousand barrels. Total storage shell capacity of Cushing Terminal is approximately 26 million barrels. A portion of the storage facilities are used for operational purposes, while the remainder are contracted to various crude oil market participants for their term storage requirements. Contract fees include fixed monthly storage fees, throughput fees for receiving and delivering crude to and from connecting pipelines and terminals, and blending fees.

In October 2021, we acquired Moda Midstream Operating, LLC, which included the Ingleside Energy Center (renamed the Enbridge Ingleside Energy Center or EIEC), located near Corpus Christi, Texas. This terminal is comprised of 15.6 million barrels of storage and 1.5 million barrels per day of export capacity. We also acquired a 20% interest in the 670-kbpd Cactus II Pipeline, a 100% interest in the 300-kbpd Viola pipeline, and a 100% interest in the 350-thousand-barrel Taft Terminal. In November 2022, we acquired an additional 10% ownership interest in Cactus II Pipeline, bringing our total non-operating ownership to 30%.

OTHER
Other includes Southern Lights Pipeline, Express-Platte System, Bakken System and Feeder Pipelines and Other.

Southern Lights Pipeline is a single stream 180 kbpd 16/18/20-inch diameter pipeline that ships diluent from the Manhattan Terminal near Chicago, Illinois to three western Canadian delivery facilities, located at the Edmonton and Hardisty terminals in Alberta and the Kerrobert terminal in Saskatchewan. Both the Canadian portion of Southern Lights Pipeline and the US portion of Southern Lights Pipeline receive tariff revenues under long-term contracts with committed shippers. Southern Lights Pipeline capacity is 90% contracted with the remaining 10% of the capacity assigned for shippers to ship uncommitted volumes.

The Express-Platte System consists of the Express pipeline and the Platte pipeline, and crude oil storage of approximately 5.6 million barrels. It is an approximate 2,736 kilometer (1,700 mile) long crude oil transportation system, which begins at Hardisty, Alberta, and terminates at Wood River, Illinois. The 310 kbpd Express pipeline carries crude oil to US refining markets in the Rocky Mountains area, including Montana, Wyoming, Colorado and Utah. The 145 to 164 kbpd Platte pipeline, which interconnects with the Express pipeline at Casper, Wyoming, transports crude oil predominantly from the Bakken shale and western Canada to refineries in the Midwest. Express pipeline capacity is typically committed under long-term take-or-pay contracts with shippers. A small portion of Express pipeline capacity and all of the Platte pipeline capacity is used by uncommitted shippers who pay only for the pipeline capacity they actually use in a given month.

The Bakken System consists of the North Dakota System and the Bakken Pipeline System. The North Dakota System services the Bakken in North Dakota and is comprised of a crude oil gathering and interstate pipeline transportation system. The gathering system provides delivery to Clearbrook, Minnesota for service on the Lakehead system or a variety of interconnecting pipeline and rail export facilities. The interstate portion of the system has both US and Canadian components that extend from Berthold, North Dakota into Cromer, Manitoba.

Tariffs on the US portion of the North Dakota System are governed by the FERC. The Canadian portion is categorized as a Group 2 pipeline, and as such, its tolls are regulated by the CER on a complaint basis. Tolls on the interstate pipeline system are based on long-term take-or-pay agreements with anchor shippers.

We have an effective 27.6% interest in the Bakken Pipeline System, which connects the Bakken formation in North Dakota to markets in eastern PADD II and the US Gulf Coast. The Bakken Pipeline System consists of the Dakota Access Pipeline (DAPL) from the Bakken area in North Dakota to Patoka, Illinois, and the Energy Transfer Crude Oil Pipeline (ETCO) from Patoka, Illinois to Nederland, Texas. Current capacity is 750 kbpd of crude oil with the potential to be expanded through additional pumping horsepower. The Bakken Pipeline System is anchored by long-term throughput commitments from a number of producers.

Feeder Pipelines and Other includes a number of liquids storage assets and pipeline systems in Canada and the US.

Key assets included in Feeder Pipelines and Other are the Hardisty Contract Terminal and Hardisty Storage Caverns located near Hardisty, Alberta, a key crude oil pipeline hub in western Canada and the Southern Access Extension (SAX) pipeline which originates in Flanagan, Illinois and delivers to Patoka, Illinois. We have an effective 65% interest in the 300 kbpd SAX pipeline. The majority of the SAX pipeline's capacity is commercially secured under long-term take-or-pay contracts with shippers.

Feeder Pipelines and Other also includes Patoka Storage, the Toledo pipeline system and the Norman Wells (NW) System. Patoka Storage is comprised of four storage tanks with 480 thousand barrels of shell capacity located in Patoka, Illinois. The 101 kbpd Toledo pipeline system connects with the Lakehead System and delivers to Ohio and Michigan. The 45 kbpd NW System transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta and has a cost-of-service rate structure based on established terms with shippers.

COMPETITION

Competition for our liquids pipelines network comes primarily from infrastructure or logistics alternatives that transport liquid hydrocarbons from production basins in which we operate to markets in Canada, the US and internationally. Competition from existing and proposed pipelines is based primarily on access to supply, end use markets, the cost of transportation, contract structure and the quality and reliability of service. Additionally, volatile crude price differentials and insufficient pipeline capacity on either our or competitors' pipelines can make transportation of crude oil by rail competitive, particularly to markets not currently served by pipelines.

We believe that our liquids pipelines systems will continue to provide competitive and attractive options to producers in the Western Canadian Sedimentary Basin (WCSB), North Dakota, and the Permian Basin, due to our market access, competitive tolls and flexibility through our multiple delivery and storage points. We also employ long-term agreements with shippers, which mitigates competition risk by ensuring consistent supply to our liquids pipelines network. We have a proven track record of successfully executing projects to meet the needs of our customers.

SUPPLY AND DEMAND

We have an established and successful history of being the largest transporter of crude oil to the US, the world's largest market for crude oil. While we expect US demand for Canadian crude oil production will support the use of our infrastructure for the foreseeable future, North American and global crude oil supply and demand fundamentals are shifting, and we have a role to play in this transition by developing long-term transportation options that enable the efficient flow of crude oil from supply regions to end-user markets, both domestic and global.

The COVID-19 pandemic had a significant negative impact on the crude oil market in 2020 with decreased demand from the economic slowdown and government imposed mobility restrictions. However, since 2021, global crude oil demand has been recovering to levels close to pre-pandemic highs. International prices have strengthened to multi-year highs as global demand has outpaced the return of supply as publicly traded producers have adopted a more disciplined approach to capital allocation for new drilling.

Our Mainline System throughput, as measured at the Canada/US border at Gretna, Manitoba ended the year delivering 3.1 mmbpd. Refinery demand in the upper Midwest PADD II market has been strong given the economic recovery and enhanced mobility demand. On the US Gulf Coast, lower supply of heavy crude from Latin America and the Middle East is driving increased demand for Canadian heavy crude.

Global crude oil demand in most base case forecasts is expected to grow into the next decade, primarily driven by emerging economies in regions outside the Organization for Economic Cooperation and Development (OECD), such as India and China. In North America, demand growth for transportation fuels is expected to moderate over time due to vehicle fuel efficiency improvement and increasing sales of electric vehicles.

New supply to meet this growing demand is expected to primarily come from Organization of the Petroleum Exporting Countries (OPEC) countries and North America. Growth in supply from OPEC is anticipated to be led by Saudi Arabia and the United Arab Emirates with their significant low cost reserves and could be supplemented by the return of sanctioned Iranian production. Growth in North America is expected to be driven by the Permian Basin which is a large and cost competitive light crude oil resource base. In addition, heavy crude oil growth is expected from the WCSB as additional egress availability will support expansion of existing projects and some potential new greenfield facilities.

The anticipated combination of long-term demand growth in non-OECD nations, domestic demand contraction over time, and continued production growth in the Permian Basin and WCSB highlights the importance of our strategic asset footprint and reinforces the need for additional export oriented infrastructure. We believe that we are well positioned to meet these evolving supply and demand fundamentals through expansion of system capacity for incremental access to the US Gulf Coast, and through further development of our new EIEC in Corpus Christi, the largest crude oil export facility in North America.

Opposition to fossil fuel development in conjunction with evolving consumer preferences and new technology could underpin accelerated energy transition scenarios impacting long-term supply and demand of crude oil. We continue to closely monitor the evolution of all of these factors to be able to pro-actively adapt our business to help meet our customers' and society's energy needs.

GAS TRANSMISSION AND MIDSTREAM

Gas Transmission and Midstream consists of our investments in natural gas pipelines and gathering and processing facilities in Canada and the US, including US Gas Transmission, Canadian Gas Transmission, US Midstream and other assets.

US GAS TRANSMISSION

US Gas Transmission includes ownership interests in Texas Eastern Transmission, L.P. (Texas Eastern), Algonquin Gas Transmission, LLC (Algonquin), Maritimes & Northeast (M&N) (US and Canada), East Tennessee Natural Gas, LLC (East Tennessee), Gulfstream Natural Gas System, L.L.C. (Gulfstream), Sabal Trail Transmission, LLC (Sabal Trail), NEXUS Gas Transmission Pipeline, LLC (NEXUS), Valley Crossing Pipeline, LLC. (Valley Crossing), Southeast Supply Header, LLC (SESH), Vector Pipeline L.P. (Vector) and certain other gas pipeline and storage assets. The US Gas Transmission business primarily provides transmission and storage of natural gas through interstate pipeline systems for customers in various regions of the northeastern, southern and midwestern US.

The Texas Eastern interstate natural gas transmission system extends from supply and demand centers in the Gulf Coast region of Texas and Louisiana to supply and demand centers in Ohio, Pennsylvania, New Jersey and New York. Texas Eastern's onshore system has a peak day capacity of 12.04 billion cubic feet per day (bcf/d) of natural gas on approximately 13,765 kilometers (8,553 miles) of pipeline and associated compressor stations. Texas Eastern is also connected to four affiliated storage facilities that are partially or wholly-owned by other entities within the US Gas Transmission business.

The Algonquin interstate natural gas transmission system connects with Texas Eastern’s facilities in New Jersey and extends through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to M&N US. The system has a peak day capacity of 3.09 bcf/d of natural gas on approximately 1,820 kilometers (1,131 miles) of pipeline with associated compressor stations.

M&N US has a peak day capacity of 0.83 bcf/d of natural gas on approximately 552 kilometers (343 miles) of mainline interstate natural gas transmission system, including associated compressor stations, which extends from northeastern Massachusetts to the border of Canada near Baileyville, Maine. M&N Canada has a peak day capacity of 0.55 bcf/d on approximately 885 kilometers (550 miles) of interprovincial natural gas transmission mainline system that extends from Goldboro, Nova Scotia to the US border near Baileyville, Maine. We have a 78% interest in M&N US and M&N Canada.

East Tennessee’s interstate natural gas transmission system has a peak day capacity of 1.86 bcf/d of natural gas, crosses Texas Eastern’s system at two locations in Tennessee and consists of two mainline systems totaling approximately 2,449 kilometers (1,522 miles) of pipeline in Tennessee, Georgia, North Carolina and Virginia, with associated compressor stations. East Tennessee has a LNG storage facility in Tennessee and also connects to the Saltville storage facilities in Virginia.

Gulfstream is an approximately 1,199 kilometer (745 mile) interstate natural gas transmission system with associated compressor stations. Gulfstream has a peak day capacity of 1.39 bcf/d of natural gas from Mississippi, Alabama, Louisiana and Texas, crossing the Gulf of Mexico to markets in central and southern Florida. We have a 50% interest in Gulfstream.

Sabal Trail is an approximately 832 kilometer (517 mile) interstate pipeline that provides firm natural gas transportation. Facilities include a pipeline, laterals and various compressor stations. The pipeline infrastructure is located in Alabama, Georgia and Florida, and adds approximately 1.0 bcf/d of capacity enabling the access of onshore gas supplies. We have a 50% interest in Sabal Trail.

NEXUS is an approximately 414 kilometer (257 mile) interstate natural gas transmission system with associated compressor stations. NEXUS transports natural gas from our Texas Eastern system in Ohio to our Vector interstate pipeline in Michigan, with peak day capacity of 1.4 bcf/d. Through its interconnect with Vector, NEXUS provides a connection to Dawn Hub, the largest integrated underground storage facility in Canada and one of the largest in North America, located in southwestern Ontario adjacent to the Greater Toronto Area. We have a 50% interest in NEXUS.

Valley Crossing is an approximately 285 kilometer (177 mile) intrastate natural gas transmission system, with associated compressor stations. The pipeline infrastructure is located in Texas and provides market access of up to 2.6 bcf/d of design capacity to the Comisión Federal de Electricidad, Mexico’s state-owned utility.

SESH is an approximately 462 kilometer (287 mile) interstate natural gas transmission system with associated compressor stations. SESH extends from the Perryville Hub in northeastern Louisiana where the shale gas production of eastern Texas, northern Louisiana and Arkansas, along with conventional production, is reached from six major interconnections. SESH extends to Alabama, interconnecting with 14 major north-south pipelines and three high-deliverability storage facilities and has a peak day capacity of 1.1 bcf/d of natural gas. We have a 50% interest in SESH.

Vector is an approximately 560 kilometer (348 mile) pipeline travelling between Joliet, Illinois in the Chicago area and Ontario. Vector can deliver 1.745 bcf/d of natural gas, of which 455 million cubic feet per day (mmcf/d) is leased to NEXUS. We have a 60% interest in Vector.

Transmission and storage services are generally provided under firm agreements where customers reserve capacity in pipelines and storage facilities. The vast majority of these agreements provide for fixed reservation charges that are paid monthly regardless of the actual volumes transported on the pipelines, plus a small variable component that is based on volumes transported, injected or withdrawn, which is intended to recover variable costs.

Interruptible transmission and storage services are also available where customers can use capacity if it exists at the time of the request and are generally at a higher toll than long-term contracted rates. Interruptible revenues depend on the amount of volumes transported or stored and the associated rates for this service. Storage operations also provide a variety of other value-added services including natural gas parking, loaning and balancing services to meet customers’ needs.

CANADIAN GAS TRANSMISSION

Canadian Gas Transmission is comprised of Westcoast Energy Inc.’s (Westcoast) British Columbia (BC) Pipeline, Alliance Pipeline and other minor midstream gas gathering pipelines.

BC Pipeline provides natural gas transmission services, transporting processed natural gas from facilities located primarily in northeastern BC to markets in BC and the US Pacific Northwest. It has a peak day capacity of 3.6 bcf/d of natural gas on approximately 2,950 kilometers (1,833 miles) of transmission pipeline in BC and Alberta, as well as associated mainline compressor stations. BC Pipeline is regulated by the CER under cost-of-service regulation.

Alliance Pipeline is an approximately 3,000 kilometer (1,864 mile) integrated, high-pressure natural gas transmission pipeline with approximately 860 kilometers (534 miles) of lateral pipelines and related infrastructure. It transports liquids-rich natural gas from northeast BC, northwest Alberta and the Bakken area in North Dakota to the Alliance Chicago gas exchange hub downstream of the Aux Sable Liquid Products LP natural gas liquids (NGL) extraction and fractionation plant at Channahon, Illinois. The system has a peak day capacity of 1.8 bcf/d of natural gas. We have a 50% interest in Alliance Pipeline.

The majority of transportation services provided by Canadian Gas Transmission are under firm agreements, which provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipeline, plus a small variable component that is based on volumes transported to recover variable costs. Canadian Gas Transmission also provides interruptible transmission services where customers can use capacity if it is available at the time of request. Payments under these services are based on volumes transported.

US MIDSTREAM
US Midstream includes a 42.7% interest in each of Aux Sable Liquid Products LP and Aux Sable Midstream LLC, and a 50% interest in Aux Sable Canada LP (collectively, Aux Sable). Aux Sable Liquid Products LP owns and operates a NGL extraction and fractionation plant at Channahon, Illinois, outside Chicago, near the terminus of Alliance Pipeline. Aux Sable also owns facilities connected to Alliance Pipeline that facilitate delivery of liquids-rich natural gas for processing at the Aux Sable plant. These facilities include the Palermo Conditioning Plant and the Prairie Rose Pipeline in the Bakken area of North Dakota, owned and operated by Aux Sable Midstream US, and Aux Sable Canada's interests in the Montney area of BC, comprising the Septimus Pipeline. Aux Sable Canada also owns a facility which processes refinery/upgrader offgas in Fort Saskatchewan, Alberta.

As of August 17, 2022, US Midstream also includes a 13.2% effective economic interest in DCP Midstream, LP (DCP). Prior to August 17, 2022, we had a 28.3% effective economic interest in DCP. DCP is a master limited partnership, with a diversified portfolio of assets, engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; producing, fractionating, transporting, storing and selling NGL; and recovering and selling condensate. DCP owns and operates more than 36 plants and approximately 86,905 kilometers (54,000 miles) of natural gas and natural gas liquids pipelines, with operations in nine states across major producing regions.

OTHER
Other consists primarily of our offshore assets. Enbridge Offshore Pipelines is comprised of 11 natural gas gathering and FERC regulated transmission pipelines and four oil pipelines. These pipelines are located in four major corridors in the Gulf of Mexico, extending to deepwater developments, and include almost 2,100 kilometers (1,300 miles) of underwater pipe and onshore facilities with total capacity of approximately 6.5 bcf/d.

COMPETITION
Our natural gas transmission and storage businesses compete with similar facilities that serve our supply and market areas in the transmission and storage of natural gas. The principal elements of competition are location, rates, terms of service, flexibility and reliability of service.

The natural gas transported in our business competes with other forms of energy available to our customers and end-users, including electricity, coal, propane, fuel oils, nuclear and renewable energy. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, levels of business activity, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Competition exists in all markets that our businesses serve. Competitors include interstate/interprovincial and intrastate/intraprovincial pipelines or their affiliates and other midstream businesses that transport, gather, treat, process and market natural gas or NGL. Because pipelines are generally the most efficient mode of transportation for natural gas over land, the most significant competitors of our natural gas pipelines are other pipeline companies.

SUPPLY AND DEMAND
Our gas transmission assets make up one of the largest natural gas transportation networks in North America, driving connectivity between prolific supply basins and major demand centers within the continent. Our systems have been integral to the transition in supply and demand markets over the last decade, and we expect to continue to play a part as the energy landscape evolves.

Natural gas production in the Appalachian and Permian basins has grown dramatically in the past decade. Today, these regions produce more than 47 bcf/d of natural gas on a combined basis. Improved technology and increased shale gas drilling have increased the supply of low-cost natural gas. As well, there has been, and continues to be, a corresponding increase in demand for our natural gas infrastructure in North America. Through a series of expansions and reversals on our core systems, combined with the execution of greenfield projects and strategic acquisitions, we have been able to meet the needs of both producers and consumers. Our US Gas Transmission systems were initially designed to transport natural gas from the Gulf Coast to the supply-constrained northeast markets. Our asset base now has the capability to transport diverse bi-directional supply to the northeast, southeast, Midwest, Gulf Coast and LNG markets on a fully subscribed and highly utilized basis.

The northeast market continues its role as a predominantly supply constrained region with steady demand. The bi-directional capabilities offered by our US Gas Transmission system allow us to deliver in an efficient manner to our regional customers. The region has seen an increase in natural gas supply due to the development of the Marcellus and Utica shales in the Appalachia region.

The southeast market is linked to multiple, highly liquid supply pools that include the Marcellus and Utica shale developments, offering consistent supply and stable pricing to a growing population of end-use customers across our multiple systems under long-term, utility-like arrangements.

With connectivity to Appalachian and western Canadian supply through our systems, the Midwest market has access to two of the lowest cost gas producing regions on the continent. As demand in the region is expected to continue to grow by over 2.0 bcf/d over the next decade, maintaining this link will remain important. Flexibility in supply for this market is especially critical to maintaining liquidity and price stability as natural gas continues to replace coal-fired generation.

Gulf Coast demand growth is being driven by an increase in the volume of LNG exports, an ongoing wave of gas-intensive petrochemical facilities, along with power generation and additional pipeline exports to Mexico. Demand in these markets in the region is anticipated to grow by more than 20.0 bcf/d through 2040. The Gulf Coast market has been the beneficiary of low-cost capacity on our assets as the relationship between supply and market centers has shifted. Such cost-effective capacity is difficult to access or replicate, offering existing shippers and transporters stability of capacity and utilization. Tide-water market access and proximity to Mexico continue to make this region a platform of global trade as pipeline and LNG exports continue their growth trajectory. In 2022, the US exported over 10.6 bcf/d of natural gas to LNG markets, primarily from the Gulf Coast region.

Western Canada, not unlike other supply hubs, is a source of low-cost supply seeking access to premium markets in North America and globally. One of the few vital links to demand centers in the Pacific Northwest are our own systems in the region, which are highly utilized. The continental supply profile has shifted to natural gas shale plays such as the Montney and Duvernay within western Canada. These supply shifts have shaped our growth strategies and affect the nature of the projects anticipated in the capital expenditures discussed below in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects.*

Global energy demand is expected to increase approximately 24% by 2050, according to the recently released International Energy Agency's Stated Policy Scenario, driven primarily by economic growth in non-OECD countries. According to the Stated Policy Scenario, natural gas will play an important role in meeting this energy demand, and gas consumption is anticipated to grow by approximately 13% during this period as one of the world's most significant energy sources. North American exports are expected to play a significant part in meeting global demand, underscoring the ability of our assets to remain highly utilized by shippers, and highlighting the need for incremental transportation solutions across North America, as well as further build-out of export facilities to meet international demand.

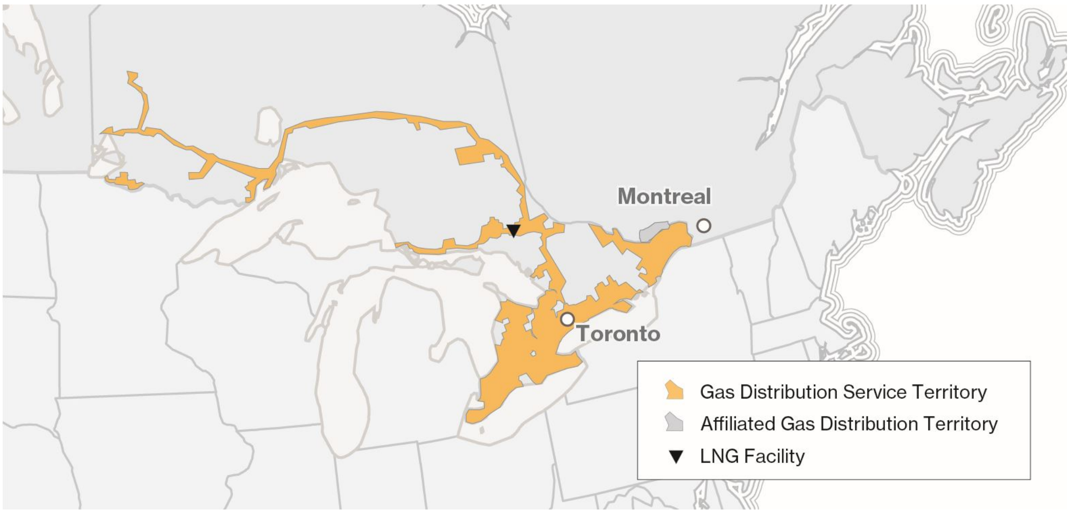
The long-term impacts of the Ukraine conflict on global gas markets are still unclear. Europe has experienced a rapid increase in natural gas prices, largely as a result of reduced natural gas supply from Russia. Global LNG markets have responded, and natural gas storage volumes entering the winter season in Europe were strong. However, these LNG cargos have largely been diverted from Asian markets, and over time the LNG market is expected to normalize.

Europe continues to seek lower-carbon gas supplies and has accelerated plans to develop hydrogen as an alternative to natural gas. The global hydrogen market is still relatively immature, but with incentives being put in place such as those in the US Inflation Reduction Act, hydrogen production at large scale is becoming increasingly commercialized, which has led to a growing export market. Given its proximity to low-cost natural gas supplies and suitable geologic storage for carbon dioxide (CO2), the US Gulf Coast is well positioned to be a leading export hub to supply blue hydrogen to international markets. Given these rapidly changing global fundamentals, and coupled with growing appetite for lower-carbon hydrogen, we believe we are well positioned to provide value-added solutions to shippers and meet both regional and international demand.

Opposition to natural gas development, including new pipeline projects, has been increasing in recent years. This may challenge continued growth of the North American gas market and the ability to efficiently connect supply and demand. We are responding to the need for regional infrastructure with additional investments in Canadian and US gas transportation facilities. Progress on the development and construction of our commercially secured growth projects is discussed in Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects.

GAS DISTRIBUTION AND STORAGE

Gas Distribution and Storage consists of our natural gas utility operations, the core of which is Enbridge Gas Inc. (Enbridge Gas), which serves residential, commercial and industrial customers throughout Ontario. This business segment also includes natural gas distribution activities in Québec.



ENBRIDGE GAS

Enbridge Gas is a rate-regulated natural gas distribution utility with storage and transmission services. Enbridge Gas' distribution system, supported by storage and compression assets, carries natural gas from the point of local supply to customers and serves residential, commercial and industrial customers across Ontario.

There are three principal interrelated aspects of the natural gas distribution business in which Enbridge Gas is directly involved: Distribution, Transportation and Storage.

Distribution

Enbridge Gas' principal source of revenue arises from distribution of natural gas to customers. The services provided to residential, small commercial and industrial heating customers are primarily on a general service basis, without a specific fixed term or fixed price contract. The services provided to larger commercial and industrial customers are usually on an annual contract basis under firm or interruptible service contracts. Under a firm contract, Enbridge Gas is obligated to deliver natural gas to the customer up to a maximum daily volume. The service provided under an interruptible contract is similar to that of a firm contract, except that it allows for service interruption at Enbridge Gas' option primarily to meet seasonal or peak demands. The Ontario Energy Board (OEB) approves rates for both contract and general services. The distribution system consists of approximately 149,000 kilometers (92,584 miles) of pipelines that carry natural gas from the point of local supply to customers.

Customers have a choice with respect to natural gas supply. Customers may purchase and deliver their own natural gas to points upstream of the distribution system or directly into Enbridge Gas' distribution system, or, alternatively, they may choose a system supply option, whereby customers purchase natural gas from Enbridge Gas' supply portfolio. To acquire the necessary volume of natural gas to serve its customers, Enbridge Gas maintains a diversified natural gas supply portfolio, acquiring supplies on a delivered basis in Ontario, as well as acquiring supply from multiple supply basins across North America.

Transportation

Enbridge Gas contracts for firm transportation service, primarily with TransCanada Pipelines Limited (TransCanada), Vector and NEXUS, to meet its annual natural gas supply requirements. The transportation service contracts are not directly linked with any particular source of natural gas supply. Separating transportation contracts from natural gas supply allows Enbridge Gas flexibility in obtaining its own natural gas supply and accommodating the requests of its direct purchase customers for assignment of TransCanada capacity. Enbridge Gas forecasts the natural gas supply needs of its customers, including the associated transportation and storage requirements.

In addition to contracting for transportation service, Enbridge Gas offers firm and interruptible transportation services on its own Dawn-Parkway pipeline system. Enbridge Gas' transmission system consists of approximately 5,500 kilometers (3,418 miles) of high pressure pipeline and five mainline compressor stations and has an effective peak daily demand capacity of 7.6 bcf/d. Enbridge Gas' transmission system also links an extensive network of underground storage pools at the Tecumseh Gas Storage facility and Dawn Hub (collectively, Dawn) to major Canadian and US markets, and forms an important link in moving natural gas from western Canada and US supply basins to central Canadian and northeastern US markets.

As the supply of natural gas in areas close to Ontario has continued to grow, there has been increased demand to access these diverse supplies at Dawn and transport them along the Dawn-Parkway pipeline system to markets in Ontario, eastern Canada and the northeastern US. Enbridge Gas delivered 2,162 bcf of gas through its distribution and transmission system in 2022. A substantial amount of Enbridge Gas' transportation revenue is generated by fixed annual demand charges, with the average length of a long-term contract being approximately 15 years and the longest remaining contract term being 18 years.

Storage
Enbridge Gas' business is highly seasonal as daily market demand for natural gas fluctuates with changes in weather, with peak consumption occurring in the winter months. Utilization of storage facilities permits Enbridge Gas to take delivery of natural gas on favorable terms during off-peak summer periods for subsequent use during the winter heating season. This practice permits Enbridge Gas to minimize the annual cost of transportation of natural gas from its supply basins, assists in reducing its overall cost of natural gas supply and adds a measure of security in the event of any short-term interruption of transportation of natural gas to Enbridge Gas' franchise areas.

Enbridge Gas' storage facility at Dawn is located in southwestern Ontario, and has a total working capacity of approximately 284 bcf in 34 underground facilities located in depleted gas fields. Dawn is the largest integrated underground storage facility in Canada and one of the largest in North America. Approximately 180 bcf of the total working capacity is available to Enbridge Gas for utility operations. Enbridge Gas also has storage contracts with third parties for 21 bcf of storage capacity.

Dawn offers customers an important link in the movement of natural gas from western Canadian and US supply basins to markets in central Canada and the northeast US. Dawn's configuration provides flexibility for injections, withdrawals and cycling. Customers can purchase both firm and interruptible storage services at Dawn. Dawn offers customers a wide range of market choices and options with easy access to upstream and downstream markets. During 2022, Dawn provided services such as storage, balancing, gas loans, transport, exchange and peaking services to over 200 counterparties.

A substantial amount of Enbridge Gas' storage revenue is generated by fixed annual demand charges, with the average length of a long-term contract being approximately four years and the longest remaining contract term being 14 years.

GAZIFÈRE
We wholly own Gazifère, a natural gas distribution company that serves approximately 44,000 customers in western Québec. Gazifère is regulated by the Québec Régie de l'énergie.

COMPETITION
Enbridge Gas' distribution system is regulated by the OEB and is subject to regulation in a number of areas, including rates. Enbridge Gas is not generally subject to third-party distribution competition within its franchise areas.

Enbridge Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include weather, price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation including the federal carbon pricing law, governmental regulations, the ability to convert to alternative fuels and other factors.

SUPPLY AND DEMAND
We anticipate that demand for natural gas in North America will stabilize over the long term with continued growth in peak day demands, however, there are risks to the natural gas market that may challenge its growth prospects. Net-zero carbon policies, evolving customer preferences for lower-carbon fuels and more efficient technologies, combined with increasing opposition to natural gas development in North America, may reduce the markets' ability to efficiently deploy capital to connect supply and demand. We monitor these factors closely to be able to develop our business strategy to align with shifts in customer preferences and public policy requirements.

We expect demand for natural gas connections in Ontario to maintain its recent growth profile due to continued population growth and with competitively priced natural gas expected to continue to provide a strong price advantage relative to alternate energy options, even with increasing carbon charges. Specific interest in natural gas connections is expected to come from communities that are not currently serviced by natural gas in Ontario.

Enbridge Gas continues to focus on promoting conservation and energy efficiency by undertaking activities focused on reducing natural gas consumption through various demand side management programs offered across all markets and sourcing supply with a smaller carbon footprint. In addition to our existing and proposed RNG programs, we are also expanding our efforts to source other lower-carbon supplies, such as responsibly sourced natural gas, and H2.

The storage and transportation marketplace continues to respond to changing natural gas supply dynamics, including a recovered supply environment which was negatively impacted by the global pandemic.

Over the past decade, growth in the North American gas supply landscape, driven mainly by the development of unconventional gas resources in the Montney, Permian, Marcellus and Utica supply basins, has resulted in lower annual commodity prices and narrower seasonal price spreads. However, over the past year, geopolitical unrest has increased and lead to elevated concerns with energy security in regions such as Europe and Asia. In response, one of the key supply sources supporting global energy security has been US LNG, which has introduced additional competition for North American supply. These market dynamics have resulted in higher and more volatile natural gas prices across many US and Canadian natural gas trading points. Unregulated storage values are primarily determined by the difference in value between winter and summer natural gas prices. Despite the recent volatility exhibited in natural gas prices, storage values have been relatively stable.

RENEWABLE POWER GENERATION

Renewable Power Generation consists primarily of investments in wind and solar assets, as well as geothermal, waste heat recovery, and transmission assets. In North America, assets are primarily located in the provinces of Alberta, Saskatchewan, Ontario and Québec, and in the states of Colorado, Texas, Indiana and West Virginia. We are also developing several solar self-power projects along our oil and gas rights-of-way in North America. In Europe, we hold equity interests in operating offshore wind facilities in the coastal waters of the United Kingdom, France, and Germany, as well as interests in several offshore wind projects under construction and active development in France and the United Kingdom.

Combined Renewable Power Generation investments represent approximately 2,175 MW of net generation capacity, which primarily consists of approximately:

- 1,389 MW generated by North American wind facilities;
- 377 MW generated by European offshore wind facilities;
- 187 MW to be generated by the Fécamp and Calvados Offshore Wind projects in France, both of which are currently under construction;
- 6 MW to be generated by the Provence Grand Large Floating Offshore Wind project in France, which is under construction; and
- 93 MW generated by North American solar facilities in operation, with an additional 97 MW in projects in pre-construction and under construction.

The vast majority of the power produced from these facilities is sold under long-term PPAs.

In September 2022, we acquired renewable energy project developer TGE with a development portfolio of wind, solar, and energy storage projects in Texas, Nebraska, Illinois, Indiana, Virginia, Pennsylvania, and Wyoming. TGE's development portfolio includes 3.9 GW of conditionally sold renewable generation projects and an additional 3 GW of wholly-owned projects in development. Following its acquisition of TGE, Enbridge became one of the top 15 renewable energy project developers in the US.

Renewable Power Generation also includes our 25% interest in the East-West Tie, a 450-MW transmission line in northwestern Ontario, which entered operations in March 2022.

JOINT VENTURES / EQUITY INVESTMENTS

The investments in the Canadian wind and solar assets (excluding self-power) and two of the US renewable assets are held within a joint venture in which we maintain a 51% interest and which we manage and operate.

We also own interests in European offshore wind facilities through the following joint ventures:

- a 24.9% interest in Rampion Offshore Wind, located in the United Kingdom;
- a 25.4% interest in Hohe See and Albatros Offshore Wind, located in Germany;
- a 25.5% interest in the Saint-Nazaire Offshore Wind project, located in France;
- a 25% interest in the Provence Grande Large Floating Offshore Wind project, under construction in France;
- a 17.9% interest in the Fécamp Offshore Wind project, under construction in France; and
- a 21.7% interest in the Calvados Offshore Wind project, under construction in France.

COMPETITION

Renewable Power Generation operates in the North American and European power markets, which are subject to competition and supply and demand fundamentals for power in the jurisdictions in which they operate. The majority of revenue is generated pursuant to long-term PPAs (or has been substantially hedged). As such, the financial performance is not significantly impacted by fluctuating power prices arising from supply/demand imbalances or the actions of competing facilities during the term of the applicable contracts. However, the renewable energy sector includes large utilities, small independent power producers and private equity investors, which are expected to aggressively compete for new project development opportunities and for the right to supply customers when contracts expire.

To grow in an environment of heightened competition, we strategically seek opportunities to collaborate with well-established renewable power developers and financial partners and to target regions with commercial constructs consistent with our low risk business model. In addition, we have expertise in completing and delivering large scale infrastructure projects.

SUPPLY AND DEMAND

Renewable power generation in North America and Europe is expected to grow significantly over the next 20 years due to the replacement of older fossil fuel-based sources of electricity generation in support of announced governmental carbon emissions reduction targets. Any additional governmental actions toward reducing emissions and/or increasing electrification will further accelerate renewable electricity demand growth and electrification across all sectors.

On the demand side, North American economic growth over the longer term and the continued electrification and transition to lower-carbon strategies within the residential, transportation and industrial sectors are expected to drive growing electricity demand. Furthermore, voluntary GHG emissions reduction targets are becoming increasingly expected by stakeholders, which is driving significant demand from corporate electricity end-users for clean electricity and environmental attributes. However, continued efficiency gains are expected to make the economy less energy-intensive and temper overall demand growth.

On the supply side in North America, legislation is accelerating the retirement of aging coal-fired generation, while generation from conventional nuclear power is also forecast to decline. As a result, North America requires significant new generation capacity from preferred technologies. Gas-fired and renewable energy facilities, including solar and wind (which make up the bulk of our renewable power assets), are generally the preferred sources to replace coal-fired generation due to their lower-carbon intensities. Governments are also proposing tax incentives to support low-emission and renewable energy generation resource development.

The falling capital and operating costs of wind and solar, combined with their improving capacity factors, are expected to continue the ongoing trend of making renewable energy more competitive and support investment over the long-term, regardless of available government incentives. Generation from renewable sources is expected to double over the next two decades in North America. Aside from the construction of new wind and solar facilities, other growth opportunities include repowering projects to increase output from, and extending the project-life of, our existing facilities.

In Europe, the renewable energy outlook is robust. Demand for electricity is expected to gradually increase over the next two decades, driven by electrification of transportation and buildings, and the desire to reduce reliance on gas sourced from Russia. Energy efficiency gains are expected to temper, but not eliminate, demand growth. Renewable power is expected to play a significant role in Europe’s ability to meet its aggressive lower-carbon and renewable energy targets.

On the supply side, the International Energy Agency expects coal to fall by more than 90% from 2020 levels, while nuclear is expected to fall by one-third, by 2040. Over the same period, it anticipates power generation from renewable sources will more than double, including installed (onshore and offshore) wind more than doubling and photovoltaics solar power nearly tripling. We, through our European joint ventures, continue to invest in offshore wind projects in the United Kingdom, France and Germany, and to explore opportunities, to meet the growing demand.

ENERGY SERVICES

The Energy Services businesses in Canada and the US provide physical commodity marketing and logistical services to North American refiners, producers, and other customers.

Energy Services is primarily focused on servicing customers across the value chain and capturing value from quality, time, and location price differentials when opportunities arise. To execute these strategies, Energy Services transports and stores on both Enbridge-owned and third party assets using a combination of contracted long-term and short-term pipeline, storage, railcar, and truck capacity agreements.

COMPETITION
Energy Services' earnings are primarily generated from arbitrage opportunities which, by their nature, can be replicated by competitors. An increase in market participants entering into similar arbitrage strategies could have an impact on our earnings. Efforts to mitigate competition risk include diversification of the marketing business by transacting at the majority of major hubs in North America and establishing long-term relationships with clients and pipelines.

ELIMINATIONS AND OTHER

Eliminations and Other includes operating and administrative costs that are not allocated to business segments, the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiaries. The principal activity of our captive insurance subsidiaries is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. Eliminations and Other also includes new business development activities and corporate investments.

REGULATION

GOVERNMENT REGULATION
Pipeline Regulation
Our Liquids Pipelines and Gas Transmission and Midstream assets are subject to numerous operational rules and regulations mandated by governments or applicable regulatory authorities, breaches of which could result in fines, penalties, operating restrictions and an overall increase in operating and compliance costs.

In the US, our interstate pipeline operations are subject to pipeline safety laws and regulations administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA), an agency within the United States Department of Transportation (DOT). These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These laws and regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines and to operate them within permissible pressures.

PHMSA continues to review existing regulations and establish new regulations to support safety standards that are designed to improve operations integrity management processes. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will result in additional costs on new pipeline projects as well as on existing operations. In this climate of increasingly stringent regulation, pipeline failure or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it may have an adverse effect on our operations, capital expenditures, earnings, cash flows, financial condition and competitive advantage.

Our ability to establish transportation and storage rates on our US interstate natural gas facilities is subject to regulation by the FERC, whose rulings and policies could have an adverse impact on the ability to recover the full cost of operating these pipeline and storage assets, including a reasonable rate of return. Regulatory or administrative actions by FERC such as rate proceedings, applications to certify construction of new facilities, and depreciation and amortization policies can affect our business, including decreasing tariff rates and revenues and increasing our costs of doing business.

In Canada, our pipelines are subject to safety regulations administered by the CER or provincial regulators. Applicable legislation and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our pipelines. Among other obligations, this regulatory framework imposes requirements to monitor and maintain the integrity of our pipelines.

As in the US, laws and regulations addressing pipeline safety in Canada were enacted over the past few years. The changes demonstrate an increased focus on the implementation of management systems to address key areas, such as emergency management, integrity management, safety, security and environmental protection. The CER also has authority to impose administrative monetary penalties for non-compliance with the regulatory regime it administers, as well as to impose financial requirements for future abandonment and major pipeline releases.

A key component of pipeline safety and reliability is the approach to integrity management that uses reliability targets and safety case assessments. A long history of extensive inline inspection has provided detailed knowledge of the assets in our pipeline systems. Our pipelines are assessed and maintained in a proactive manner ensuring reliability targets are met. Furthermore, the integrity management program has an independent step to check the results of integrity assessments to validate the effectiveness of the program and to ensure that the operational risk remains as low as reasonably practicable throughout the integrity inspection and assessment cycle. As inspection technology, pipeline materials and construction practices improve with time, and new data on threats and pipeline condition are gathered, our methods of maintaining fitness for service evolves, with a strong focus on continual improvement in every aspect of integrity management.

Our pipelines also face economic regulatory risk. Broadly defined, economic regulatory risk is the risk that governments or regulatory agencies reject proposed commercial arrangements, applications or policies, upon which future and current operations are dependent. Our pipelines are subject to the actions of various regulators, including the CER and the FERC, with respect to the tariffs and tolls. The rejection of applications for approval of new tariff structures or proposed commercial arrangements and changes in interpretation of existing regulations by courts or regulators could have an adverse effect on our revenues and earnings.

Gas Distribution and Storage
Our gas distribution and storage utility operations are regulated by the OEB and the Québec Régie de l’énergie, among others. To the extent that the regulators’ future actions are different from current expectations, the timing and amount of recovery or refund of amounts recorded in the Consolidated Statements of Financial Position, or amounts that would have been recorded in the Consolidated Statements of Financial Position in the absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

Enbridge Gas' distribution rates, commencing in 2019, are set under a five-year incentive regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% productivity factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved return on equity (ROE).

In October 2022, Enbridge Gas filed its application with the OEB to establish a 2024 through 2028 rate setting framework. The application and framework seek approval to establish 2024 base rates on a cost-of-service basis and to establish a price cap IR rate setting mechanism to be used for the remainder of the term (2025 - 2028). The OEB has determined it will hear the application in two phases, with Phase 1 addressing items that affect rates effective January 1, 2024, and Phase 2 addressing items that will affect rates subsequent to January 1, 2024. An OEB decision is expected on Phase 1 of the application in the second half of 2023.

Enbridge Gas continues to develop opportunities to support a lower-carbon future in Ontario. In 2021, we received OEB approval of an Integrated Resource Planning (IRP) framework and integrated the framework into our planning practices. The framework requires Enbridge Gas to consider facility and non-pipe demand and/or supply side alternatives (IRP alternatives) to address the systems needs of its regulated operations, where certain parameters have been met. The framework also allows Enbridge Gas to pursue an IRP alternative (or combination of IRP alternatives and facility alternative) where it is found to be in the best interests of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management. Enbridge Gas has reviewed its system needs as part of its 2023-2032 Asset Management Plan and is now evaluating the technical and economic feasibility of IRP alternatives for the projects. A summary of the IRP evaluation statuses has been filed as part of Enbridge Gas' 2024 Rebasing Application.

Renewable Power Generation
Renewable Power Generation is subject to numerous operational rules and regulations mandated by governments or applicable regulatory authorities, breaches of which could result in fines, penalties, operating restrictions and an overall increase in operating and compliance costs.

The North American Electric Reliability Council (NERC) is an international regulatory authority responsible for establishing and enforcing reliability standards to reduce risks to the reliability and security of the grid in Canada, the US, and Mexico. It is subject to oversight from the FERC in the US and provincial governments in Canada. The FERC has authority over many markets in the US and is tasked with ensuring safe, reliable, and secure interstate transmission of electricity, natural gas, and oil. This includes establishing reliability standards and determining certain pricing aspects of transmission development and access, among others. NERC and FERC standards and pricing decisions are also updated from time to time and could impact our operations, capital expenditures, earnings, and cash flows, though some of these impacts could be positive for our business.

At the US federal level, our Renewable Power Generation assets are subject to legislation overseen by the US Fish and Wildlife Service, which is aimed at reducing the impact of development and human activity on wildlife, along with other federal environmental permitting legislation. These federal environmental laws are subject to change from time to time which could require Enbridge to obtain new permits, update practices, or amend operations and operating expenditures.

In Canada, the Federal Government does not generally regulate the electricity sector though it has imposed a federal carbon price on other sectors via its output-based pricing system (OBPS) and has proposed a Clean Electricity Regulation (CE Regulation) that would require Canada's electricity grid reach net-zero by 2035. The CE Regulation is expected to come into effect in 2023.

Policy changes may also provide new opportunities for existing assets and new developments. The United States passed the Inflation Reduction Act in late 2022, which established long-term production and investment tax credits for renewable power generation, battery storage projects and for related manufacturing supply chains. Similarly, Canada proposed in its Fall Economic Statement competitive tax credits for renewable power generation and battery storage projects, which it anticipates passing in 2023. Changes to these tax programs could impact development plans.

Renewable Power Generation is also subject to Provincial and State regulations governing the energy resource mix on the grid, emissions levels of the electricity grid, and market regulations related to emergency operations, extreme weather preparedness, and market participation, among others. These regulations may change from time to time, which could impact Enbridge's operations and increase the costs of participating in regional electricity markets.

Our Renewable Power Generation assets in France and Germany each have federal policies in place and are subject to directives and regulations established and enforced by the European Union (EU). These include the Renewable Energy Directive (most recently, RED II passed set targets through 2030), the European Green Deal, and ongoing work on financing mechanisms and transmission directives and programs. The EU is also responsible for establishing environmental protection rules and permitting standards. During 2022, member states of the EU introduced extraordinary and temporary measures to address high energy prices including caps and demand reduction goals. As the minimum PPA prices in Germany and France will still be honored, there will not be any negative implications to our PPA prices. The federal policies and regulations in place are subject to change from time to time, which could impact our operations and related expenditures; however, the EU's general direction is to facilitate increased renewable power integration to its grid.

The United Kingdom (UK) government is responsible for establishing renewable energy and carbon pricing policies for the entire UK, as well as long-term electricity sector planning and procurement mechanisms and structure for auctions that are administered at the national level, e.g., England, Scotland, within the UK. Each country within the UK is also responsible for establishing its own environmental and permitting regulations. This process is still ongoing following Brexit and in some cases continues to result in more volatile merchant power prices; however, expanded interconnectors to Europe and policies aimed at increasing domestic renewable capacity are in progress. Government-imposed temporary price controls, effective January 1, 2023, were introduced during 2022 to address the significant increase in energy prices. The impact of merchant exposure on our Renewable Power Generation asset in the UK is limited by fixed revenue payments backed by the UK government.

Energy Services

Energy Services is regulated by government authorities in the areas of commodity trading, import and export compliance and the transportation of commodities. Non-compliance with governing rules and regulations could result in fines, penalties and operating restrictions. These consequences would have an adverse effect on operations, earnings, cash flows, financial condition and competitive advantage. Energy Services retains dedicated professional staff and has a robust regulatory compliance program (including targeted training) to mitigate these potential risks associated with the business.

In the US, commodity marketing is regulated by the Commodity Futures Trading Commission, the SEC, the Federal Trade Commission, the various commodity exchanges, the US Department of Justice and state regulators. The provincial and territorial securities regulators similarly regulate commodity marketing within Canada and are members of the Canadian Securities Administrators. These various regulators enforce, among other things, the prohibition of market manipulation, fraud and disruptive trading.

The export of natural gas out of Alberta is regulated by the Alberta Energy Regulator (AER). The import and export of commodities between Canada and the US is subject to regulation by the CER and the US Department of Energy, as well as customs authorities. In particular, import and export permits are required, with associated regular reporting requirements. Breaches of import and export rules and permits could result in an inability to perform day to day operations, and therein negatively impact the earnings of the business.

The transportation of crude oil and natural gas liquids by railcar or truck is regulated by the US DOT, Transport Canada and provincial regulation. Each jurisdiction requires compliance with security, safety, emergency management, and environmental laws and regulations related to ground transportation of commodities. Risks associated with transportation of crude or natural gas liquids include unplanned releases. In the event of a release, remediation of the affected area would be required. Energy Services engages third parties, such as Emergency Response Assistance Canada, the Chemical Transportation Emergency Center and the Canadian Transport Emergency Center to assist in such remediation.

ENVIRONMENTAL REGULATION

Pipeline Regulation

Our Liquids Pipelines and Gas Transmission and Midstream assets are subject to numerous federal, state and provincial environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, water discharge and waste. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits and other approvals.

In particular, in the US, compliance with major Clean Air Act regulatory programs may cause us to incur significant capital expenditures to obtain permits, evaluate off-site impacts of our operations, install pollution control equipment, and otherwise assure compliance. Some states in which we operate are establishing new state implementation plans which have new emissions limits to comply with ozone standards regulated under the National Ambient Air Quality Standards. In 2015, the ozone standards were lowered once again from 75 parts per billion (ppb) to 70 ppb, which may require states to implement additional emissions regulations. The precise nature of these compliance obligations at each of our facilities has not been finally determined and may depend in part on future regulatory changes. In addition, compliance with new and emerging environmental regulatory programs may significantly increase our operating costs compared to historical levels.

In the US, climate change action is evolving at federal, state and regional levels. The Supreme Court decision in Massachusetts v. Environmental Protection Agency in 2007 established that GHG emissions were pollutants subject to regulation under the Clean Air Act. Pursuant to federal regulations, we are currently subject to an obligation to report our GHG emissions at our largest emitting facilities but are not generally subject to limits on emissions of GHGs. The current US presidential administration has also announced that policies designed to combat climate change and reduce GHG emissions will be a key legislative and regulatory priority, and thus stricter emissions limits and air quality enforcement actions are likely. In addition, a number of states have joined regional GHG initiatives, and a number are developing their own programs that would mandate reductions in GHG emissions. Public interest groups and regulatory agencies are increasingly focusing on the emission of methane associated with natural gas development and transmission as a source of GHG emissions. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are uncertain.

Canada has adopted a pan-Canadian approach to pricing carbon emissions to incent GHG emission reductions across all sectors of the economy. This approach was adopted in 2016 and entails both a consumer price on carbon, and an intensity-based system for industry which addresses competitiveness and carbon leakage. Provinces and territories may implement their own system of carbon pricing provided it meets the federal benchmark (and if they fail to do so the federal system will be imposed on them). In March 2022, Canada published its 2030 Emissions Reduction Plan (ERP) which builds on the Pan-Canadian Framework, and Net-Zero Emissions Accountability Act, and details the roadmap for Canada to meet its domestic climate target of a 40-45% reduction in GHG emissions by 2030 and attaining net-zero emissions by 2050. The ERP details the complementary policies and programs that Canada will enact to enable it to meet its domestic climate goal. Effective January 1, 2023, the federal carbon price was increased from $50 to $65 per tonne of carbon dioxide equivalent (tCO2e). This will increase by $15 per tonne and rise to $170 per tCO2e in 2030.

Gas Distribution and Storage
Our Gas Distribution and Storage operations, facilities and workers are subject to municipal, provincial and federal legislation which regulates the protection of the environment and the health and safety of workers. Environmental legislation primarily includes regulation of spills and emissions to air, land and water; hazardous waste management; the assessment and management of excess soil and contaminated sites; protection of environmentally sensitive areas, and species at risk and their habitats; and the reporting and reduction of GHG emissions.

Gas distribution system operation, as with any industrial operation, has the potential risk of abnormal or emergency conditions, or other unplanned events that could result in releases or emissions exceeding permitted levels. These events could result in injuries to workers or the public, adverse impacts to the environment, property damage and/or regulatory infractions including orders and fines. We could also incur future liability for soil and groundwater contamination associated with past and present site activities.

In addition to gas distribution, we also operate gas storage facilities and a small volume of oil and brine production in southwestern Ontario. Environmental risk associated with these facilities has the potential for unplanned releases. In the event of a release, remediation of the affected area would be required. There would also be potential for fines and orders under environmental legislation, and potential third-party liability claims by any affected landowners.

The gas distribution system and our other operations must maintain environmental approvals and permits from regulators to operate. As a result, these assets and facilities are subject to periodic inspections and/or audits. Reports are submitted to our regulators as required to demonstrate we are in good standing with our environmental requirements. Failure to maintain regulatory compliance could result in operational interruptions, fines, and/or orders for additional pollution control technology or environmental mitigation.

As environmental regulations continue to evolve and become more stringent, the cost to maintain compliance and the time required to obtain approvals continues to increase. A recent example includes the implementation of the new excess soil management requirements (Ontario Regulation 406/19) which has resulted in an increase in soil management costs and effort.

As in previous years, in 2022, we reported operational GHG emissions, including emissions from stationary combustion, flaring, venting and fugitive sources to Environment and Climate Change Canada (ECCC), the Ontario Ministry of Environment, Conservation and Parks, and a number of voluntary reporting programs. In accordance with the provincial GHG regulations, stationary combustion and flaring emissions related to storage and transmission operations were verified in detail by a third-party accredited verifier with no material discrepancies found.

Enbridge Gas utilizes emissions data management processes and systems to help with the data capture and mandatory and voluntary reporting needs. Quantification methodologies and emission factors are updated in our systems as required. Enbridge Gas continues to work with industry associations to refine quantification methodologies and emissions factors, as well as best management practices to minimize emissions.

In October 2018, the federal government confirmed that Ontario is subject to the federal government’s carbon pricing program, otherwise known as the Federal Carbon Pricing Backstop Program. This program consists of two components: a carbon charge levied on fossil fuels, including natural gas, and an OBPS.

The federal carbon charge took effect on April 1, 2019 at a rate of 3.91 cents/cubic meter (m3) of natural gas and is applicable to the majority of customers. Enbridge Gas is registered as a natural gas distributor with the Canada Revenue Agency and remits the federal carbon charge on a monthly basis. The charge increases annually on April 1 of each year by 1.96 cents/m3, rising to 9.79 cents/m3 in 2022. In December 2020, the federal government announced plans to increase the federal carbon price by $15 per tonne each year beginning in 2023, rising to $170 per tCO_2e in 2030. Enbridge Gas estimates that this will equate to a federal carbon charge on natural gas of approximately 33.31 cents/m3 in 2030.

The OBPS component came into effect in Ontario on January 1, 2019 and ended on December 31, 2021. Under OBPS, a registered facility has a compliance obligation for the portion of their emissions that exceeds their annual facility emissions limit, which is calculated based on the sector specific output-based standard and annual production. From 2019 to 2021, Enbridge Gas was registered with ECCC as an emitter in the OBPS program and has an annual compliance obligation associated with the combustion and flaring emissions from its natural gas pipeline transmission system. As a registered facility under OBPS, Enbridge Gas submitted an annual report along with the required verification report from an accredited third-party verifier who found no material misstatements. Enbridge Gas was required to remit payment for facility emissions that exceed its annual facility emissions limit by December of the year following a compliance period. In accordance with the regulations, Enbridge Gas made payment for the 2021 compliance obligation in December 2022.

In September 2020, Ontario and the federal government announced that the federal government has accepted that Ontario's Emission Performance Standards (EPS) will replace the federal OBPS for industrial facilities. In March 2021, the federal government announced that the federal OBPS would stand down in Ontario at the end of 2021 and Ontario would transition to the EPS effective January 1, 2022. In September 2021, the Greenhouse Gas Pollution Pricing Act was amended to remove Ontario as a covered province, enabling the EPS to take effect on January 1, 2022. Effective January 1, 2022, Enbridge Gas transitioned out of the federal OBPS to the provincial EPS. Enbridge Gas is registered with the Ministry of the Environment, Conservation and Parks as a covered facility under the EPS and has an annual compliance obligation for its facility-related stationary combustion and flaring emissions associated with its transmission and storage operations. Enbridge Gas must remit payment annually on the portion of emissions that exceed its total annual emissions limit. Payment is due the year following a compliance period and as such, Enbridge Gas will remit payment for its 2022 EPS compliance obligation in 2023.

Enbridge Gas applies to the OEB annually through a Federal Carbon Pricing Program application for approval of just and reasonable rates effective April 1 each year for the Enbridge Gas Distribution Inc. and Union rate zones, to recover the costs associated with the Federal Carbon Charge and EPS Regulation as a pass-through to customers.

Renewable Power Generation

In March 2022, the Federal Government of Canada released a white paper setting out its plans for caps on emissions on Canada's electricity grid with the intention of reaching a net-zero grid by 2035. The government subsequently proposed a CE Regulation framework and provided technical details for the program, which would cap emissions from electricity generation sources at, or near zero tCO_2e per megawatt hour. Details of related compliance payments and potential credit generation opportunities are under review and the CE Regulation is expected to come into effect in 2023. Enbridge's Renewable Power Generation resources are substantially non-emitting.

HUMAN CAPITAL RESOURCES

WORKFORCE SIZE AND COMPOSITION

As at December 31, 2022, we had approximately 11,100 regular employees, including approximately 1,600 unionized employees across our North American operations. This total rises to just over 13,000 if temporary employees and contractors are included. We have a strong preference for direct employment relationships but where we have collectively bargained-for employees, we have mature working relationships with our labor unions and the parties have traditionally committed themselves to the achievement of renewal agreements without a work stoppage.

SAFETY

We believe all injuries, incidents and occupational illnesses are preventable. Our overall focus on employee and contractor safety, including through the COVID-19 pandemic, continues to result in strong performance compared against industry benchmarks and we are actively engaged in continuous improvement exercises as we pursue our goal of zero incidents.

DIVERSITY, EQUITY AND INCLUSION

In 2020, we announced Enbridge's ESG goals – including goals to increase representation of women, underrepresented ethnic and racial groups (including Indigenous peoples), people with disabilities and veterans – to ensure our workforce is reflective of the communities where we operate. In executing on our ESG strategy, we continue to track progress towards these representation goals in 2022. Consistent with our culture, we remain committed to open, two-way dialogue related to our goals, enhancing transparency and accountability for all stakeholders.

Diversity Representation Goals

Workforce comprised of **40%** **women** by 2025

28% from **underrepresented ethnic and racial groups** in our workforce by 2025

7% workplace representation of **U.S. protected veterans** by 2025

6% **People with disabilities** included in our workforce by 2025

3.5% **representation** within our workforce of **Indigenous people** by 2025

PRODUCTIVITY AND DEVELOPMENT

We continually invest in our people's personal and professional development because we recognize their success is our success. Every year, employees are provided access to a range of development and re-skilling opportunities through a variety of channels, including: extensive catalog of self-directed learning (10,000+ external courses plus proprietary Enbridge University courses); on-the-job learning opportunities and rotational assignments; curated leadership development programs; educational reimbursement; and developmental relationships with mentors through our formal mentor-protégé matching program.

EXECUTIVE OFFICERS

The following table sets forth information regarding our executive officers as at February 10, 2023:

Name	Age	Position
Gregory L. Ebel	58	President & Chief Executive Officer
Vern D. Yu	56	Executive Vice President, Corporate Development, Chief Financial Officer & President, New Energy Technologies
Colin K. Gruending	53	Executive Vice President & President, Liquids Pipelines
Cynthia L. Hansen	58	Executive Vice President & President, Gas Transmission and Midstream
Byron C. Neiles	57	Executive Vice President & Chief Administrative Officer
Robert R. Rooney	66	Executive Vice President & Chief Legal Officer
Matthew A. Akman	55	Senior Vice President, Corporate Strategy & President, Power
Michele E. Harradence	54	Senior Vice President & President, Gas Distribution
Laura J. Sayavedra	55	Senior Vice President, Safety & Reliability, Projects and Unify

Gregory L. Ebel was appointed President and Chief Executive Officer on January 1, 2023. Mr. Ebel is also a member of the Enbridge Board of Directors. Mr. Ebel served as Chair of the Enbridge Board of Directors following the merger of Enbridge and Spectra Energy Corp (Spectra Energy) in 2017 until January 1, 2023. Prior to that time, he served as Chairman, President and CEO of Spectra Energy from 2009 until February 27, 2017. Previously, Mr. Ebel also served as Spectra Energy's Group Executive and Chief Financial Officer beginning in 2007, President of Union Gas Limited from 2005 until 2007, and Vice President, Investor & Shareholder Relations of Duke Energy Corporation from 2002 until 2005.

Vern D. Yu was appointed Executive Vice President, Corporate Development, Chief Financial Officer & President, New Energy Technologies on January 1, 2023. Prior thereto, he served as Executive Vice President, Corporate Development and Chief Financial Officer from March 2022 to December 2022, and Executive Vice President and Chief Financial Officer from October 2021 to March 2022. Mr. Yu has oversight for all of Enbridge's financial affairs including investor relations, financial reporting, financial planning, treasury, tax, insurance, risk and audit management functions. He is also responsible for overseeing Enbridge's new energy technology ventures. Previously, Mr. Yu served as Executive Vice President and President, Liquids Pipelines from January 2020 to October 2021; President and Chief Operating Officer for Liquids Pipelines from June 2019 to December 2019; and Executive Vice President and Chief Development Officer from May 2016 to June 2019.

Colin K. Gruending was appointed Executive Vice President and President, Liquids Pipelines on October 1, 2021. Mr. Gruending is responsible for the overall leadership and operations of Enbridge's Liquids Pipelines business. Previously, he served as our Executive Vice President and Chief Financial Officer from June 2019 to October 2021; Senior Vice President, Corporate Development and Investment Review from May 2018 to June 2019; and Vice President, Corporate Development and Investment Review from February 2017 to May 2018.

Cynthia L. Hansen was appointed Executive Vice President and President, Gas Transmission and Midstream on March 1, 2022. Ms. Hansen is responsible for the overall leadership and operations of Enbridge's natural gas pipeline and midstream business across North America. Previously, she served as our Executive Vice President, Gas Distribution and Storage from June 2019 to March 2022 and as Executive Vice President, Utilities and Power Operations from February 2017 to June 2019. Ms. Hansen is also the Executive Sponsor for Asset and Work Management Transformation across Enbridge, working with other business unit leaders.

Byron C. Neiles was appointed Executive Vice President & Chief Administrative Officer on January 1, 2023. Prior thereto, he served as Executive Vice President, Corporate Services from May 2016 to December 2022. Mr. Neiles has oversight of our information technology, human resources, real estate, supply chain management, and public affairs, communications and sustainability functions.

Robert R. Rooney was appointed Executive Vice President and Chief Legal Officer on February 1, 2017. Mr. Rooney leads our legal, ethics and compliance, security and aviation teams across the organization.

Matthew A. Akman was appointed Senior Vice President, Corporate Strategy & President, Power on January 1, 2023. Prior thereto, he was Senior Vice President, Strategy, Power & New Energy Technologies from October 2021 to December 2022, and Senior Vice President, Strategy & Power from June 2019 to October 2021. Mr. Akman is responsible for the overall leadership and operations of Enbridge's power business and also leads our corporate strategy efforts. Mr. Akman joined Enbridge in early 2016 as our head of Corporate Strategy and also previously held responsibilities for Corporate Development and Investor Relations.

Michele E. Harradence was appointed Senior Vice President & President, Gas Distribution and Storage on March 1, 2022. She is responsible for the overall leadership and operations of Ontario-based Enbridge Gas Inc., as well as Gazifère, which serves the Gatineau region of Québec. Prior to assuming her current role, Ms. Harradence was Senior Vice President and Chief Operations Officer of Enbridge's Gas Transmission and Midstream business unit from June 2019 to March 2022. Prior thereto, she was Senior Vice President Operations, Gas Transmission and Midstream from February 2017 to June 2019.

Laura J. Sayavedra was appointed Senior Vice President, Safety & Reliability, Projects and Unify on March 1, 2022. This includes oversight of our safety, capital project execution, environment, land, and right of way functions, and business leadership of our multi-year Unify transformation project. Prior to that, she led Finance Transformation at Enbridge, and was also Vice President & Treasurer for Spectra Energy, and CFO of Spectra Energy Partners. She has held various finance, strategy, and business development executive leadership roles.

ADDITIONAL INFORMATION

Additional information about us is available on our website at www.enbridge.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. The aforementioned information is made available in accordance with legal requirements and is not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K. We make available free of charge, through our website, annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as well as proxy statements, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Reports, proxy statements and other information filed with the SEC may also be obtained through the SEC's website (www.sec.gov).

ENBRIDGE GAS INC.

Additional information about Enbridge Gas can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2022, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to Enbridge Gas and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ENBRIDGE PIPELINES INC.

Additional information about Enbridge Pipelines Inc. (EPI) can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2022, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to EPI and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

WESTCOAST ENERGY INC.

Additional information about Westcoast can be found in its financial statements and MD&A for the year ended December 31, 2022, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to Westcoast and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ITEM 1A. RISK FACTORS

The following risk factors could materially and adversely affect our business, operations, financial results, market price or value of our securities. This list is not exhaustive, and we place no priority or likelihood based on order of presentation or grouping under sub-captions.

RISKS RELATED TO CLIMATE CHANGE

Climate change risks could adversely affect our business, operations and financial results, and these effects could be material.

Climate change is a systemic risk that presents both physical and transition risks to our organization. A summary of these risks is discussed below. Given the interconnected nature of climate impacts, we also discuss these risks within the context of other risks impacting Enbridge throughout *Item 1A. Risk Factors*.

Climate change and its associated impacts may increase our exposure to, and magnitude of, other risks identified in *Item 1A. Risk Factors*. Our business, financial condition, results of operations, cash flows, reputation, access to and cost of capital or insurance, business plans or strategy may all be materially adversely impacted as a result of climate change and its associated impacts.

PHYSICAL RISKS

Climate-related physical risks as a result of changing and more extreme weather, can damage our assets and affect the safety and reliability of our operations and has had such impacts in the past. Climate-related physical risks may be acute or chronic. Acute physical risks are those that are event-driven, including increased frequency and severity of extreme weather events, such as heavy snowfall, heavy rainfall, floods, landslides, fires, hurricanes, cyclones, tornados, tropical storms, ice storms, and extreme temperatures. Chronic physical risks are longer-term shifts in climate patterns, such as long-term changes in precipitation patterns, or sustained higher temperatures, which may cause sea level rises or chronic heat waves.

Our assets are exposed to potential damage or other negative impacts from these kinds of events, which could result in reduced revenue from business disruption or reduced capacity and may also lead to increased costs due to repairs and required adaptation measures. Such events may also result in loss of life or injury or damage to property and the environment. We have experienced operational interruptions and damage to our assets from such weather events in the past, and we expect to experience climate-related physical risks in the future, potentially with increasing frequency or severity.

TRANSITION RISKS

Transition risks relate to the transition to a lower-emissions economy, which may increase our cost of operations, impact our business plans, and influence stakeholder decisions about our company, each of which could adversely impact our reputation, strategic plan, business, operations or financial results. These transition risks include:

- ***Policy and legal risks***
  Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations regarding reduction of GHG emissions, adaptation to climate change, transition to a lower-carbon economy, and disclosure of climate-related matters. Such policies, laws and regulations vary at the federal, state, provincial and municipal levels in which Enbridge operates and are continually evolving. International multilateral agreements, the obligations adopted thereunder, increasing physical impacts of climate change, changing political and public opinion and legal challenges concerning the adequacy of climate-related policy brought against governments and corporations, among other factors, are expected to accelerate the implementation of these measures. Efforts to regulate or restrict GHG emissions could negatively impact demand for the products we transport. Significant expenditures and resources could be required in order to meet new regulatory requirements. In addition, there has been an increase in climate and disclosure-related litigation against governments as well as energy companies. There is no assurance that our company will not be impacted by such litigation.

  In addition, Enbridge is required to adhere to a number of implicit and explicit carbon-pricing mechanisms. Many jurisdictions in which we operate are either increasing the stringency of existing, or introducing new, legislation or public policy to address climate change and reduce GHG emissions. These mechanisms may present climate-related transition risk to our business strategy, impacting both commodity demand and the overall energy mix we deliver. Carbon pricing mechanisms may expose us to increased costs as well as increasing energy costs to our customers. Our operations are subject to both explicit carbon prices (i.e., in BC) and implicit carbon prices (i.e., Canadian federal OBPS). These requirements are evolving; in Canada, the federal government is considering options to cap and cut oil and gas sector GHG emissions, which may impact our business, including a new cap-and-trade system under the *Canadian Environmental Protection Act, 1999* or modification of the current carbon pricing approach under the *Greenhouse Gas Pollution Pricing Act*.

- ***Technology risks***
  Our success in executing our strategic plan, including adapting to the energy transition over time and attaining our GHG emissions reduction goals and targets, depends, in part, on technology (including technology still under development), innovation and continued diversification with renewable power and other lower-carbon energy infrastructure as well as modernization of our infrastructure to reduce GHG emissions. Achieving our GHG emissions reduction goals and targets could require significant capital expenditures and resources, with the potential that the costs required to achieve our goals and targets materially differ from our original estimates and expectations. Similarly, there is a risk that emissions reduction technology does not materialize as expected, making it more difficult to reduce emissions.

- ***Market risks***
  Climate change concerns, increase in demand for lower-carbon and zero-emissions energy, alternative and new energy sources and technologies, changing customer behavior and reduced energy consumption could impact the demand for our services or securities. The pace and scale of the transition to a lower-carbon economy may pose a risk if Enbridge diversifies either too quickly or too slowly. Similarly, uncertainty in market signals, such as abrupt and unexpected shifts in energy costs and demands, including due to climate change concerns, can impact revenue through reduced throughput volumes on our pipeline transportation systems.

- ***Reputational risks***
  We have long been committed to strong ESG practices and performance, and in November 2020, we introduced a set of ESG goals to strengthen transparency and accountability. We have set GHG emissions reduction goals and one of our strategic priorities is to adapt to the energy transition over time. If we are not able to achieve our GHG emissions reduction goals, are not able to meet future climate, emissions or other reporting requirements of regulators, or are not able to meet or manage current and future expectations and issues important to investors or other stakeholders, including those related to climate change, it could negatively impact our reputation and our business, operations or financial results.

- ***Disclosure risks***
  Finally, we currently provide certain climate-related disclosures, and from time to time, we establish and publicly announce goals and commitments to reduce our GHG emissions. These disclosures and goals, and our progress towards these commitments, may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve, and assumptions that are subject to change in the future. There can be no assurance that our current or future disclosures and goals, the pathways by which we plan to reach our goals, or the methodologies that we currently use to support our disclosures and progress towards our goals, will satisfy any new and evolving regulations and legal requirements or expectations of our stakeholders, and the costs of aligning our current disclosures and goals to any new legal requirements may be significant. Additionally, if we fail to achieve or improperly report on our progress toward achieving our emissions reduction goals and commitments, we may be subject to reputational harm, regulatory action, or other legal action.

Companies across all sectors and industries are facing changing expectations or increasing scrutiny from stakeholders related to their approach to ESG matters, including climate change and GHG emissions. Companies in the energy industry are experiencing stakeholder opposition to new infrastructure, as well as organized opposition to oil and natural gas extraction and shipment of oil and natural gas products.

Our business is undergoing significant changes driven by technological advancements and the energy transition, which could impact our strategic plan, business, operations or financial results.
Our success in executing our strategic plan, including adapting to the energy transition over time and attaining our GHG emissions reduction goals and targets depends, in part, on technology (including technology still under development), innovation and continued diversification with renewable power and other lower-carbon energy infrastructure, as well as modernization of our infrastructure to reduce GHG emissions, all of which could require significant capital expenditures and resources. Public policy relating to climate change can drive investment in lower-emissions technologies which could impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on our pipelines.

RISKS RELATED TO OPERATIONAL DISRUPTION OR CATASTROPHIC EVENTS

Operation of complex energy infrastructure involves many hazards and risks that may adversely affect our business, financial results and the environment.
These operational risks include adverse weather conditions, natural disasters, accidents, the breakdown or failure of equipment or processes, and lower than expected levels of operating capacity and efficiency. These operational risks could be catastrophic in nature.

Operational risk is also intensified by climate change. Climate change presents physical risks that may affect the safety and reliability of our operations. These include acute physical risks, such as heavy snowfall, heavy rainfall, floods, landslides, fires, hurricanes, cyclones, tornados, tropical storms, ice storms, and extreme temperatures, and chronic physical risks, such as long-term changes in precipitation patterns, or sustained higher temperatures.

Our assets and operations are exposed to potential damage or other negative impacts from these operational risks, which could result in reduced revenue from business disruption or reduced capacity and may also lead to increased costs due to repairs and required adaptation measures. Such events have led to, could in the future lead to, rupture or release of product from our pipeline systems and facilities, or loss of life or injury to people, which could result in substantial losses for which insurance may not be sufficient or available and for which we may bear part or all of the cost.

An environmental incident is an event that may cause environmental harm and could lead to increased operating and insurance costs, thereby negatively impacting earnings. An environmental incident could have lasting reputational impacts and could impact our ability to work with various stakeholders. For pipeline and storage assets located near populated areas, including residential communities, commercial business centers, industrial sites and other public gathering locations, the level of damage resulting from these events could be greater.

We have experienced such events in the past, including in 2010 on Lines 6A and 6B of the Lakehead System; in October 2018 at the BC Pipeline T-South system; in January 2019, August 2019 and May 2020 at the Texas Eastern Pipeline; impacts from the winter storm in February 2021 in Texas; and from wildfires in July 2021 and flooding in November 2021 in BC. We have incurred and expect to continue to incur significant costs in preparing for or responding to operational risks and events. We expect to continue to experience climate-related physical risks, potentially with increasing frequency and severity, and we cannot guarantee that we will not experience catastrophic or other events in the future. In addition, we could be subject to litigation and significant fines and penalties from regulators in connection with any such events.

A service interruption could have a significant impact on our operations, and negatively impact financial results, relationships with stakeholders and our reputation.
A service interruption due to a major power disruption, curtailment of commodity supply, operational incident, security incident (cyber or physical), availability of gas supply or distribution or other reasons could have a significant impact on our operations and negatively impact financial results, relationships with stakeholders, our reputation or the safety of our end customers. Service interruptions that impact our crude oil and natural gas transportation services can negatively impact shippers' operations and earnings as they are dependent on our services to move their product to market or fulfill their own contractual arrangements, and this has in the past and may again lead to claims against us. We have experienced, and may again experience, service interruptions, restrictions or other operational constraints, including in connection with the kinds of operational incidents referred to in the previous risk factor.

Our operations involve safety risks to the public and to our workers and contractors.
Several of our pipelines and distribution systems are operated in close proximity to populated areas and a major incident could result in injury or loss of life to members of the public. In addition, given the natural hazards inherent in our operations, our workers and contractors are subject to personal safety risks. A public safety incident or an injury or loss of life to our workers or contractors, which we have experienced in the past and, despite the precautions we take, may experience in the future, could result in reputational damage to us, material repair costs or increased operating and insurance costs.

Cyber attacks pose threats to our technology systems and could materially adversely affect our business, operations, reputation or financial results.
Our business is dependent upon information systems and other digital technologies for controlling our plants, pipelines and other assets, processing transactions and summarizing and reporting results of operations. The secure processing, maintenance and transmission of information is critical to our operations. A security breach of our network or systems, or the network or systems of our third-party vendors, could result in improper operation of our assets, potentially including delays in the delivery or availability of our customers' products, contamination or degradation of the products we transport, store and distribute, damage to our facilities or those of our customers, or releases of hydrocarbon products for which we could be held liable, all of which could materially adversely affect our reputation, business, operations or financial results. Furthermore, we and some of our vendors collect and store sensitive data in the ordinary course of our business, including personal information of our employees and residential gas distribution customers as well as our proprietary business information and that of our customers, suppliers, investors and other stakeholders.

Cybersecurity risks have increased in recent years as a result of the proliferation of new technologies and the increased sophistication of cyber attacks and data security breaches, as well as due to international and domestic political factors including geopolitical tensions, armed hostilities, war, civil unrest, sabotage and terrorism. Human error can also contribute to a cyber incident, and cyber attacks can be internal as well as external and occur at any point in our supply chain. Because of the critical nature of our infrastructure and our use of information systems and other digital technologies to control our assets, we face a heightened risk of cyber attacks. Cyber threat actors have attacked and threatened to attack energy infrastructure, and various government agencies have increasingly stressed that these attacks are targeting critical infrastructure, and are increasing in sophistication, magnitude, and frequency. New cybersecurity legislation, regulations and orders have been recently implemented or proposed resulting in additional actual and anticipated regulatory oversight and compliance requirements, which will require significant internal and external resources. We cannot predict the potential impact to our business of potential future legislation, regulations or orders relating to cybersecurity.

We have been, and expect to continue to be, the target of cyber-attacks against which we have deployed, and continue to deploy, security measures. Our information systems or those of our vendors or other service providers are expected to become the target of further cyber attacks or security breaches which could compromise our data and systems, affect our ability to correctly record, process and report transactions, result in the loss of information, or cause operational disruption or incidents. As a result of a cyber attack or security breach, we could also be liable under laws that protect the privacy of personal information, be subject to regulatory action, fines or penalties, incur additional costs for remediation, litigation, breach of contract or indemnity claims, or other costs, all of which could materially adversely affect our reputation, business, operations or financial results.

In addition, a cyber attack could occur and persist for an extended period without detection. Any investigation of a cyber attack or other security incident may be inherently unpredictable, and it would take time before the completion of any investigation and availability of full and reliable information. During such time, we may not know the extent of the harm or how best to remediate it, and certain errors or actions could be repeated or compounded before they are discovered and remediated, all or any of which could further increase the costs and consequences of a cyber attack or other security incident, and our remediation efforts may not be successful. The inability to implement, maintain and upgrade adequate safeguards could materially and adversely affect our results of operations, cash flows, and financial condition. As cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Furthermore, media reports about a cyber attack or other significant security incident affecting the Company, whether accurate or not, or, under certain circumstances, our failure to make adequate or timely disclosures to the public, law enforcement, other regulatory agencies or affected individuals following any such event, whether due to delayed discovery or otherwise, could negatively impact our operating results and result in other negative consequences, including damage to our reputation or competitiveness, harm to our relationships with customers, partners, suppliers and other third parties, interruption to our management, remediation or increased protection costs, significant litigation or regulatory action, fines or penalties, all of which could materially adversely affect our business, operations, reputation or financial results.

Pandemics, epidemics or infectious disease outbreaks, such as the COVID-19 pandemic, may adversely affect local and global economies and our business, operations or financial results.
Disruptions caused by pandemics, epidemics or infectious disease outbreaks could materially adversely affect our business, operations, financial results and forward-looking expectations. Governments' emergency measures to combat the spread could include restrictions on business activity and travel, as well as requirements to isolate or quarantine. The duration and magnitude of such impacts will depend on many factors that we may not be able to accurately predict. COVID-19 and government responses interrupted business activities and supply chains, disrupted travel, and contributed to significant volatility in the financial and commodity markets.

Disruptions related to pandemics, epidemics or infectious disease outbreaks could have the effect of heightening many of the other risks described in this *Item 1A. Risk Factors*.

Terrorist attacks and threats, escalation of military activity in response to these attacks or acts of war, and other civil unrest or activism could adversely affect our business, operations or financial results.
Terrorist attacks and threats (which may take the form of cyber attacks), escalation of military activity, armed hostilities, war, sabotage, or civil unrest or activism may have significant effects on general economic conditions and may cause fluctuations in consumer confidence and spending and market liquidity, each of which could adversely affect our business. Future terrorist attacks, rumors or threats of war, actual conflicts involving the US or Canada, or military or trade disruptions may significantly affect our operations and those of our customers. Strategic critical infrastructure targets, such as energy-related assets, are at greater risk of cyber attack and may be at greater risk of other future attacks than other targets in the US and Canada. The Company’s infrastructure and projects under construction could be direct targets or indirect casualties of a cyber or physical attack. In addition, increased environmental activism against pipeline construction and operation could potentially result in work delays, reduced demand for our products and services, new legislation or public policy or increased stringency thereof, or denial or delay of permits and rights-of-way.

RISKS RELATED TO OUR BUSINESS AND INDUSTRY

There are utilization risks with respect to our assets.
With respect to our Liquids Pipelines assets, we may be exposed to throughput risk on the Canadian Mainline depending upon the tolling framework we adopt for that system, and we are exposed to throughput risk under certain tolling agreements applicable to other Liquids Pipelines assets, such as the Lakehead System. A decrease in volumes transported can directly and adversely affect our revenues and earnings. Factors such as changing market fundamentals, capacity bottlenecks, regulatory restrictions, maintenance and operational incidents on our system and upstream or downstream facilities, and increased competition can all impact the utilization of our assets. Market fundamentals, such as commodity prices and price differentials, weather, gasoline price and consumption, alternative and new energy sources and technologies, and global supply disruptions outside of our control can impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on our pipelines.

With respect to our Gas Transmission and Midstream assets, gas supply and demand dynamics continue to change due to shifts in regional and global production and consumption. These shifts can lead to fluctuations in commodity prices and price differentials, resulting in oversupply of pipeline takeaway capacity in some areas and an adverse effect to the utilization of our systems. Other factors affecting system utilization include operational incidents, regulatory restrictions, system maintenance, and increased competition.

With respect to our Gas Distribution and Storage assets, customers are billed on both a fixed charge and volumetric basis and our ability to collect the total revenue requirement (the cost of providing service, including a reasonable return to the utility) depends on achieving the forecast distribution volume established in the rate-making process. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Weather is a significant driver of delivery volumes, given that a significant portion of our Gas Distribution customer base uses natural gas for space heating. Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continue to place downward pressure on consumption. In addition, conservation efforts by customers may further contribute to a decline in annual average consumption. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Even in those circumstances where we attain our respective total forecast distribution volume, our Gas Distribution business may not earn its expected ROE due to other forecast variables, such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector. Our Gas Distribution business remains at risk for the actual versus forecast large volume contract commercial and industrial volumes.

With respect to our Renewable Power Generation assets, earnings from these assets are highly dependent on weather and atmospheric conditions as well as continued operational availability of these energy producing assets. While the expected energy yields for Renewable Power Generation projects are predicted using long-term historical data, wind and solar resources are subject to natural variation from year-to-year and from season-to-season. Any prolonged reduction in wind or solar resources at any of the Renewable Power Generation facilities could lead to decreased earnings and cash flows. Additionally, inefficiencies or interruptions of Renewable Power Generation facilities due to operational disturbances or outages resulting from weather conditions or other factors, could also impact earnings.

Our assets vary in age and were constructed over many decades which causes our inspection, maintenance or repair costs to increase.

Our pipelines vary in age and were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have changed over time. Depending on the era of construction and construction techniques, some assets require more frequent inspections, which has resulted in and is expected to continue to result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our business, operations or financial results.

Competition may result in a reduction in demand for our services, fewer project opportunities or assumption of risk that results in weaker or more volatile financial performance than expected.
Our Liquids Pipelines business faces competition from competing carriers available to ship liquid hydrocarbons to markets in Canada, the US and internationally and from proposed pipelines that seek to access basins and markets currently served by our Liquids Pipelines. Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. The liquids transported in our pipelines currently, or are expected to increasingly, compete with other emerging alternatives for end-users, including, but not limited to, electric batteries, biofuels, and hydrogen. Additionally, we face competition from alternative storage facilities. Our natural gas transmission and storage businesses compete with similar facilities that serve our supply and market areas in the transmission and storage of natural gas. The natural gas transported in our business also competes with other forms of energy available to our customers and end-users, including electricity, coal, propane, fuel oils, and renewable energy. Our Renewable Power Generation business faces competition in the procurement of long-term power purchase agreements and from other fuel sources in the markets in which we operate. Competition in all of our businesses, including competition for new project development opportunities, could have a negative impact on our business, financial condition or results of operations.

Completion of our secured projects and maintenance programs are subject to various regulatory, operational and market risks, which may affect our ability to drive long-term growth.
Our project execution continues to face challenges with intense scrutiny on regulatory and environmental permit applications, politicized permitting, public opposition including protests, action to repeal permits, and resistance to land access.

Continued challenges with global supply chains have created unpredictability in materials cost and availability. Labor shortages and union strikes have increased costs of engineering and construction services.

Other events that can and have delayed project completion and increased anticipated costs include contractor or supplier non-performance, extreme weather events or geological factors beyond our control.

Changing expectations of stakeholders regarding ESG practices and climate change could erode stakeholder trust and confidence, damage our reputation and influence actions or decisions about our company and industry and have negative impacts on our business, operations or financial results.
Companies across all sectors and industries are facing changing expectations or increasing scrutiny from stakeholders related to their approach to ESG matters of greatest relevance to their business and to their stakeholders. For energy companies, climate change, GHG emissions, safety and stakeholder and Indigenous relations remain primary focus areas, while other environmental elements such as biodiversity and supply chain are ascendant. Companies in the energy industry are experiencing stakeholder opposition to new and existing infrastructure, as well as organized opposition to oil and natural gas extraction and shipment of oil and natural gas products. Changing expectations of our practices and performance across these ESG areas may impose additional costs or create exposure to new or additional risks. We are also exposed to the risk of higher costs, delays, project cancellations, loss of ability to secure new growth opportunities, new restrictions or the cessation of operations of existing pipelines due to increasing pressure on governments and regulators, and legal action, such as the legal challenges to the operation of Line 5 in Michigan and Wisconsin.

Our operations, projects and growth opportunities require us to have strong relationships with key stakeholders, including local communities, Indigenous groups and others directly impacted by our activities, as well as governments, regulatory agencies, investors and investor advocacy groups, investment funds, financial institutions, insurers and others, which are increasingly focused on ESG practices and performance.

Enhanced public awareness of climate change has driven an increase in demand for lower-carbon and zero-emissions energy. Over the past year, the invasion of Ukraine and inflationary pressure following the COVID-19 pandemic have underscored the critical need for access to secure affordable energy. Enbridge has a long history of diversifying its portfolio of businesses to align with the mix of energy that people need and want. The pace and scale of the transition to a lower-emission economy may pose a risk if Enbridge diversifies either too quickly or too slowly. Similarly, unexpected shifts in energy demands, including due to climate change concerns, can impact revenue through reduced throughput volumes on our pipeline transportation systems.

We have long been committed to strong ESG practices, performance and reporting, and in 2020 introduced a set of ESG goals to strengthen transparency and accountability. The goals include increasing diversity and inclusion within our organization and reducing GHG emissions from our operations to net-zero by 2050, with corporate and business unit action plans aligned to our strategic priority to adapt to the energy transition over time. The costs associated with meeting our ESG goals, including our GHG emissions reduction goals, could be significant. There is also a risk that some or all of the expected benefits and opportunities of achieving our ESG goals may fail to materialize, may cost more than anticipated to achieve, may not occur within the anticipated time periods or may no longer meet changing stakeholder expectations. Similarly, there is a risk that emissions reduction technologies do not materialize as expected making it more difficult to reduce emissions. If we are not able to achieve our ESG goals, are not able to meet current and future climate, emissions or related reporting requirements of regulators, or are unable to meet or manage current and future expectations regarding issues important to investors or other stakeholders (including those related to climate change), it could erode stakeholder trust and confidence, which could negatively impact our reputation, business, operations or financial results. Potential impacts could also include changing investor sentiment regarding investment in Enbridge or impair our access to and increase our cost of capital, including penalties associated with our sustainability-linked financing.

Our forecasted assumptions may not materialize as expected, including on our expansion projects, acquisitions and divestitures.
We evaluate expansion projects, acquisitions and divestitures on an ongoing basis. Planning and investment analysis is highly dependent on accurate forecasting assumptions and to the extent that these assumptions do not materialize, financial performance may be lower or more volatile than expected. Volatility and unpredictability in the economy, both locally and globally, and changes in cost estimates, project scoping and risk assessment could result in a loss of profits. Similarly, uncertainty in market signals, such as abrupt and unexpected shifts in energy costs and demands, as we saw in 2020 resulting from the COVID-19 pandemic, have impacted, and may in the future impact, revenue through reduced throughput volumes on our pipeline transportation systems.

Our insurance coverage may not fully cover our losses in the event of an accident, natural disaster or other hazardous event, and we may encounter increased cost arising from the maintenance of, or lack of availability of, insurance.
Our operations are subject to many hazards inherent in our industry. Our assets may experience physical damage as a result of an accident or natural disaster. These hazards can also cause, and in some cases have caused, personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations.

We maintain an insurance program for us, our subsidiaries and certain of our affiliates to mitigate a certain portion of our risks. However, not all potential risks arising from our operations are insurable, or are insured by us as a result of availability, high premiums and for various other reasons. The Company self-insures a significant portion of certain risks through our wholly-owned captive insurance subsidiaries, and the Company’s insurance coverage is subject to terms and conditions, exclusions and large deductibles or self-insured retentions which may reduce or eliminate coverage in certain circumstances.

The Company's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, terms, policy limits and/or deductibles can vary substantially. We can give no assurance that we will be able to maintain adequate insurance in the future at rates or on other terms we consider commercially reasonable. In such case, we may decide to self-insure additional risks.

A significant self-insured loss, uninsured loss, a loss significantly exceeding the limits of our insurance policies, a significant delay in the payment of a major insurance claim, or the failure to renew insurance policies on similar or favorable terms could materially and adversely affect our business, financial condition and results of operations.

We are exposed to the credit risk of our customers, counterparties, and vendors.
We are exposed to the credit risk of multiple parties in the ordinary course of our business. Generally, our customers are rated investment-grade, are otherwise considered creditworthy or provide us security to satisfy credit concerns. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in the creditworthiness of our customers, vendors, or counterparties. It is possible that payment or performance defaults from these entities, if significant, could adversely affect our earnings and cash flows.

Our business is exposed to changes in market prices including interest rates and foreign exchange rates. Our risk management policies cannot eliminate all risks and may result in material financial losses. In addition, any non-compliance with our risk management policies could adversely affect our business, operations or financial results.
Our use of debt financing exposes us to changes in interest rates on both future fixed rate debt issuances and floating rate debt. While our financial results are denominated in Canadian dollars, many of our businesses have foreign currency revenues or expenses, particularly the US dollar. Changes in interest rates and foreign exchange rates could materially impact our financial results.

We use financial derivatives to manage risks associated with changes in foreign exchange rates, interest rates, commodity prices, power prices and our share price to reduce volatility of our cash flows. Based on our risk management policies, substantially all of our financial derivatives are associated with an underlying asset, liability and/or forecasted transaction and not intended for speculative purposes.

These policies cannot, however, eliminate all risk, including unauthorized trading. Although this activity is monitored independently by our Risk Management function, we can provide no assurance that we will detect and prevent all unauthorized trading and other violations, particularly if deception, collusion or other intentional misconduct is involved, and any such violations could adversely affect our business, operations or financial results.

In addition, to the extent that we hedge our foreign exchange rates, interest rates or commodity prices, we will forego the benefits we would otherwise experience if these were to change in our favor. In addition, hedging activities can result in losses that might be material to our financial condition, results of operations and cash flows. Such losses have occurred in the past and could occur in the future. See Part II, *Item 7A. Quantitative and Qualitative Disclosures about Market Risk* and *Item 8. Financial Statements and Supplementary Data* for a discussion of our derivative instruments and related hedging activities.

Our business requires the retention and recruitment of a skilled and diverse workforce, and difficulties in recruiting and retaining our workforce could result in a failure to implement our business plans.
Our operations and management require the retention and recruitment of a skilled and diverse workforce, including engineers, technical personnel, other professionals and executive officers and senior management. We and our affiliates compete with other companies in the energy industry, and for some jobs the broader labor market, for this skilled workforce. If we are unable to retain current employees and/or recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

Our Liquids Pipelines growth rate and results may be directly and indirectly affected by commodity prices and government policy.
Effective December 31, 2021, the Government of Alberta lifted the oil production curtailment that was imposed in December 2018. Wide commodity price basis between Western Canada and global tidewater markets have negatively impacted producer netbacks and margins in the past years that largely resulted from pipeline infrastructure takeaway capacity from producing regions in Western Canada and North Dakota which are operating at capacity. A protracted long-term outlook for low crude oil prices could result in delay or cancellation of future projects.

The tight conventional oil plays of Western Canada, the Permian basin, and the Bakken region of North Dakota have short cycle break-even time horizons, typically less than 24 months, and high decline rates that can be well managed through active hedging programs and are positioned to react quickly to market signals. Accordingly, during periods of comparatively low prices, drilling programs, unsupported by hedging programs, will be reduced and as such, supply growth from tight oil basins may be lower, which may impact volumes on our pipeline systems.

Our Energy Services and Gas Transmission and Midstream results may be adversely affected by commodity price volatility.
Within our US Midstream assets, through our investments in DCP and Aux Sable, we are engaged in the businesses of gathering, treating and processing natural gas and natural gas liquids. The financial results of these businesses are directly impacted by changes in commodity prices. To a lesser degree, the financial results of our US Transmission business are subject to fluctuation in power prices which impact electric power costs associated with operating compressor stations.

Energy Services generates margin by capitalizing on quality, time and location differentials when opportunities arise. Changing market conditions that impact the prices at which we buy and sell commodities have in the past limited margin opportunities and impeded Energy Services' ability to cover capacity commitments and could do so again in the future. Other market conditions, such as backwardation, have likewise limited margin opportunities.

We rely on access to short-term and long-term capital markets to finance capital requirements and support liquidity needs. Cost effective access to those markets can be affected, particularly if we or our rated subsidiaries are unable to maintain an investment-grade credit rating.
A significant portion of our consolidated asset base is financed with debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations and to refinance investments originally financed with debt. Our senior unsecured long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us or our rated subsidiaries below investment-grade, our borrowing costs would increase, perhaps significantly. Consequently, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources could decrease.

We maintain revolving credit facilities at various entities to backstop commercial paper programs, for borrowings and for providing letters of credit. These facilities typically include financial covenants and failure to maintain these covenants at a particular entity could preclude that entity from accessing the credit facility, which could impact liquidity. Furthermore, if our short-term debt rating were to be downgraded, access to the commercial paper market could be significantly limited. Although this would not affect our ability to draw under our credit facilities, borrowing costs could be significantly higher.

Recently, interest rates have increased significantly. If we are not able to access capital at competitive rates or at all, our ability to finance operations and implement our strategy may be affected. An inability to access capital on favorable terms or at all may limit our ability to pursue enhancements or acquisitions that we may otherwise rely on for future growth or to refinance our existing indebtedness. Any downgrade or other event negatively affecting the credit ratings of our subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could increase our need to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing the liquidity and borrowing availability of the consolidated group.

RISKS RELATED TO GOVERNMENT REGULATION AND LEGAL RISKS

Many of our operations are regulated and failure to secure timely regulatory approval for our proposed projects, or loss of required approvals for our existing operations, could have a negative impact on our business, operations or financial results.
The nature and degree of regulation and legislation affecting permitting and environmental review for energy infrastructure companies in Canada and the US continues to evolve.

Within the US and in Canada, pipeline companies continue to face opposition from anti-energy/anti-pipeline activists, Indigenous and tribal groups and communities, citizens, environmental groups, and politicians concerned with either the safety of pipelines or their potential environmental effects. In the US, the Environmental Protection Agency redefined the Waters of the United States under Section 401 of the Clean Water Act, and the FERC released draft policy statements on the Certification of New Interstate Natural Gas Facilities and the Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Review that could introduce changes to the regulatory approval process for natural gas infrastructure. The Council for Environmental Quality published immediately applicable guidance for conducting analyses under the National Environmental Policy Act that may significantly change environmental scope and cost assessments. Many other regulations adopted during the previous US presidential administration are being challenged in multiple courts and some have been overturned by reviewing courts. The current US administration may take further action to modify or reverse regulations that were promulgated by the previous US administration.

In March of 2023, the Supreme Court of Canada will hear the Attorney General of Canada's appeal of the Alberta Court of Appeal's non-binding decision that the federal Impact Assessment Act ("IAA") is unconstitutional. The IAA includes impact assessment requirements that could apply to either federally or provincially regulated pipeline projects that fall within prescribed criteria or that the federal Minister of Environment otherwise designates for review. The potential for any pipeline project to be subject to IAA requirements adds significant uncertainty as to regulatory timelines and outcomes. The Alberta Court of Appeal found that the IAA is an impermissible federal overreach into provincial jurisdiction that would amount to a de facto expropriation of provincial natural resources and proprietary interests by the federal government. The Supreme Court of Canada will determine whether the IAA and the related Physical Activities Regulations are within the constitutional legislative authority of the Parliament of Canada, the outcome of which could impact the applicability of the legislation to provincially regulated pipeline projects.

These actions could adversely impact permitting of a wide range of energy projects. We may not be able to obtain or maintain all required regulatory approvals for our operating assets or development projects. If there is a significant delay in obtaining any required regulatory approvals, if we fail to obtain or comply with them, or if laws or regulations change or are administered in a more stringent manner, the operations of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs.

Our operations are subject to numerous environmental and climate laws and regulations, including those relating to climate change and GHG emissions and climate-related disclosure, compliance with which may require significant capital expenditures, increase our cost of operations, and affect or limit our business plans, or expose us to environmental liabilities.
We are subject to numerous environmental laws and regulations affecting many aspects of our past, current, and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste.

If we are unable to obtain or maintain all required environmental regulatory approvals and permits for our operating assets and projects or if there is a delay in obtaining any required environmental regulatory approvals or permits, the operation of existing facilities or the development of new facilities could be prevented, delayed, or become subject to additional costs. Failure to comply with environmental laws and regulations may result in the imposition of civil or criminal fines, penalties and injunctive measures affecting our operating assets. We expect that changes in environmental laws and regulations, including those related to climate change and GHG emissions, could result in a material increase in our cost of compliance with such laws and regulations, such as costs to monitor and report our emissions and install new emission controls to reduce emissions. We may not be able to include some or all of such increased costs in the rates charged for utilization of our pipelines or other facilities.

Our operations are subject to operational regulation and other requirements, including compliance with easements and other land tenure documents, and failure to comply with applicable regulations and other requirements could have a negative impact on our reputation, business, operations or financial results.
Operational risks relate to compliance with applicable operational rules and regulations mandated by governments, applicable regulatory authorities, or other requirements that may be found in easements, permits, or other agreements that provide a legal basis for our operations, breaches of which could result in fines, penalties, awards of damages, operating restrictions (including shutdown of lines) and an overall increase in operating and compliance costs.

We do not own all of the land on which our pipelines, facilities and other assets are located and we obtain the rights to construct and operate our pipelines and other assets from third parties or government entities. In addition, some of our pipelines, facilities and other assets cross Indigenous lands pursuant to rights-of-way or other land tenure interests. Our loss of these rights could have an adverse effect on our reputation, operations and financial results. We have experienced litigation in relation to certain Line 5 easements; refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates*.

Regulatory scrutiny over our assets and operations has the potential to increase operating costs or limit future projects. Regulatory enforcement actions issued by regulators for non-compliant findings can increase operating costs and negatively impact reputation. Potential regulatory changes and legal challenges could have an impact on our future earnings from existing operations and the cost related to the construction of new projects. Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environments in which we operate. While we seek to mitigate operational regulation risk by actively monitoring and consulting on potential regulatory requirement changes with the respective regulators directly, or through industry associations, and by developing response plans to regulatory changes or enforcement actions, such mitigation efforts may be ineffective or insufficient. While we believe the safe and reliable operation of our assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators or other government officials to make unilateral decisions that could disrupt our operations or have an adverse financial impact on us.

Our operations are subject to economic regulation and failure to secure regulatory approval for our proposed or existing commercial arrangements could have a negative impact on our business, operations or financial results.
Our Liquids Pipelines, Gas Transmission and Gas Distribution assets face economic regulation risk. Broadly defined, economic regulation risk is the risk that governments or regulatory agencies change or reject proposed or existing commercial arrangements or policies, including permits and regulatory approvals for both new and existing projects or agreements, upon which future and current operations are dependent. Our Mainline System, other liquids pipelines, gas transmission and distribution assets are subject to the actions of various regulators, including the CER, the FERC, and the OEB with respect to the rates, tariffs, and tolls for these assets. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable permits and tariff structure or changes in interpretations of existing regulations by courts or regulators such as with respect to the Mainline Commercial Framework, could have an adverse effect on our revenues and earnings.

Our Renewable Power Generation assets in Europe (France, Germany and the UK) are also subject to the directives, regulations and policies established and enforced by the EU and the UK government. These measures are variable and can include price controls, caps and demand reduction goals, all of which can have a negative impact on our revenues and earnings.

We are subject to changes in our tax rates, the adoption of new US, Canadian or international tax legislation or exposure to additional tax liabilities.
We are subject to taxes in the US, Canada and numerous foreign jurisdictions. Due to economic and political conditions, tax rates in various jurisdictions may be subject to significant change. Our effective tax rates could be affected by changes in the mix of earnings in countries with differing statutory tax rates, changes in the valuation of deferred tax assets and liabilities, or changes in tax laws or their interpretation. In particular, Canada has introduced interest deductibility rules, the US enacted the Inflation Reduction Act and we are anticipating a minimum tax rate to be introduced on a global basis for OECD countries. All of these measures could cause our effective tax rate to increase.

We are also subject to the examination of our tax returns and other tax matters by the US Internal Revenue Service, the Canada Revenue Agency and other tax authorities and governmental bodies. We regularly assess the likelihood of an adverse outcome resulting from these examinations to determine the adequacy of our provision for taxes. There can be no assurance as to the outcome of these examinations. If our effective tax rates were to increase, particularly in the US or Canada, or if the ultimate determination of our taxes owed is for an amount in excess of amounts previously accrued, our financial condition and operating results could be materially adversely affected.

We are involved in numerous legal proceedings, the outcomes of which are uncertain, and resolutions adverse to us could adversely affect our financial results.
We are subject to numerous legal proceedings. In recent years, there has been an increase in climate and disclosure-related litigation against governments as well as companies involved in the energy industry. There is no assurance that we will not be impacted by such litigation, or by other legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which we are involved or new matters could require additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could adversely affect our financial results or affect our reputation. Refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates* for a discussion of certain legal proceedings with recent developments.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Descriptions of our properties and maps depicting the locations of our liquids and natural gas systems are included in Part I. *Item 1. Busin*ess.

In general, our systems are located on land owned by others and are operated under easements and rights-of-way, licenses, leases or permits that have been granted by private land-owners, First Nations, Native American Tribes, public authorities, railways or public utilities. Our liquids pipeline systems have pumping stations, tanks, terminals and certain other facilities that are located on land that is owned by us and/or used by us under easements, licenses, leases or permits. Additionally, our natural gas pipeline systems have natural gas compressor stations, of which the vast majority are located on land that is owned by us, with the remainder used by us under easements, leases or permits.

Titles to Enbridge owned properties or affiliate entities may be subject to encumbrances in some cases. We believe that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of our business.

ITEM 3. LEGAL PROCEEDINGS

We are involved in various legal and regulatory actions and proceedings which arise in the ordinary course of business. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations. Refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates* for discussion of certain legal proceedings with recent developments.

SEC regulations require the disclosure of any proceeding under environmental laws to which a governmental authority is a party unless the registrant reasonably believes it will not result in monetary sanctions over a certain threshold. Given the size of our operations, we have elected to use a threshold of US$1 million for the purposes of determining proceedings requiring disclosure.

On October 17, 2022, four separate comprehensive enforcement resolutions were announced with the Minnesota Pollution Control Agency, Minnesota Department of Natural Resources (DNR), Fond du Lac Band of Lake Superior Chippewa, and Minnesota Attorney General's Office related to alleged violations that occurred during construction of Line 3 Replacement. As part of these agreements, together with the DNR's previous Administrative Penalty Order, Enbridge will provide the various entities a total of approximately US$11 million, approximately US$7.5 million of which is to provide financial assurances and fund multiple environmental and resource enhancement projects. The Minnesota Attorney General has filed a misdemeanor criminal charge for the taking of water without a permit at the Clearbrook aquifer, with this charge against us to be dismissed following one year of compliance with the state water appropriation rules.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock

Enbridge common stock is traded on the TSX and NYSE under the symbol ENB. As at February 3, 2023, there were 76,001 registered shareholders of record of Enbridge common stock. A substantially greater number of holders of Enbridge common stock are "street name" or beneficial holders, whose shares are held by banks, brokers and other financial institutions.

Securities Authorized for Issuance Under Equity Compensation Plans

The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2022.

Recent Sales of Unregistered Equity Securities

None.

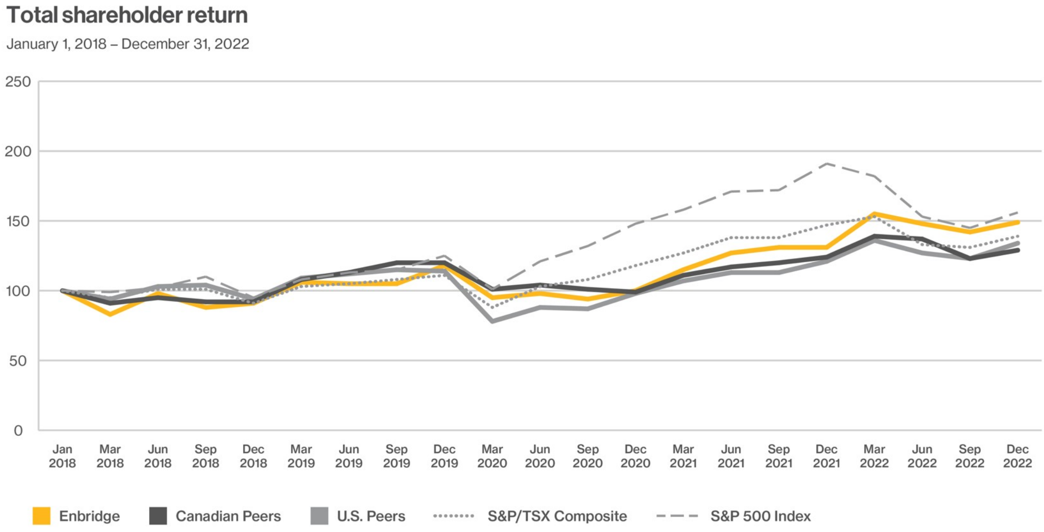
Issuer Purchases of Equity Securities

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs[1]
October 2022 (October 1 - October 31)	—	N/A	—	28,324,366
November 2022 (November 1 - November 30)	—	N/A	—	28,324,366
December 2022 (December 1 - December 31)	—	N/A	—	28,324,366

1 *On December 31, 2021, we announced that the TSX approved our prior normal course issuer bid (NCIB) to purchase, for cancellation, up to 31,062,331 of the outstanding common shares of Enbridge to an aggregate amount of up to $1.5 billion. Our prior NCIB commenced on January 5, 2022 and expired on January 4, 2023. On January 4, 2023, we announced that the TSX had approved our new NCIB, which commenced on January 6, 2023 and continues until January 5, 2024. Under the new NCIB, Enbridge may purchase, for cancellation, up to 27,938,163 of its outstanding common shares to an aggregate amount of up to $1.5 billion. Purchases may be made through the facilities of the TSX, the NYSE and other designated exchanges and alternative trading systems.*

Total Shareholder Return

The following graph reflects the comparative changes in the value from January 1, 2018 through December 31, 2022 of $100 invested in (1) Enbridge Inc.'s common shares traded on the TSX, (2) the S&P/TSX Composite index, (3) the S&P 500 index, (4) our US peer group (comprising, by stock symbols, CNP, D, DTE, DUK, EPD, ET, KMI, MMP, NEE, NI, OKE, PAA, PCG, SO, SRE and WMB) and (5) our Canadian peer group (comprising, by stock symbols, CU, FTS, PPL and TRP). The amounts included in the table were calculated assuming the reinvestment of dividends.



	January 1, 2018	December 31, 2018	2019	2020	2021	2022
Enbridge Inc.	100.00	91.90	118.86	100.80	131.30	149.54
S&P/TSX Composite	100.00	91.11	111.96	118.23	147.89	139.25
S&P 500 Index	100.00	95.62	125.72	148.85	191.58	156.88
US Peers[1]	100.00	94.80	114.97	98.40	121.17	134.17
Canadian Peers	100.00	92.00	120.56	99.72	124.49	129.22

1 For the purpose of the graph, it was assumed that CAD:US dollar conversion ratio remained at 1:1 for the years presented.

ITEM 6. [Reserved]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with "Forward-Looking Information" and "Non-GAAP and Other Financial Measures", Part I. *Item 1A. Risk Factors* and our consolidated financial statements and the accompanying notes included in Part II. *Item 8. Financial Statements and Supplementary Data* of this Annual Report on Form 10-K.

This section of our Annual Report on Form 10-K discusses 2022 and 2021 items and year-over-year comparisons between 2022 and 2021. For discussion of 2020 items and year-over-year comparisons between 2021 and 2020, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* of our Annual Report on Form 10-K for the year ended December 31, 2021.

RECENT DEVELOPMENTS

Chair of the Board and CEO Appointments

Pamela L. Carter was appointed Chair of the Board of Directors (the Board) effective January 1, 2023. Gregory L. Ebel was appointed as President and Chief Executive Officer (CEO) effective the same date. Mr. Ebel succeeds retiring President and CEO, Al Monaco. To support Mr. Ebel through the transition, Mr. Monaco will serve as an advisor until June 30, 2023. Mr. Ebel will continue as a member of the Board. Ms. Carter has served as a director of the Board since 2017 and with Spectra Energy Corp since 2007. Most recently she has served as Chair of the Human Resources & Compensation Committee of the Board, as a member of the Sustainability and Safety & Reliability Committees and as a former Chair of the Governance Committee.

ASSET TRANSACTIONS

Joint Venture Merger Transaction to Advance US Gulf Coast Oil Strategy

On August 17, 2022, we completed a joint venture merger transaction with Phillips 66 (P66) resulting in a single joint venture, DCP Midstream LLC, holding both Enbridge Inc.'s (Enbridge) and P66's indirect ownership interests in Gray Oak Pipeline, LLC (Gray Oak) and DCP Midstream, LP (DCP), as well as an agreement to realign our respective economic and governance interests in the underlying business operations. Our effective economic interest in Gray Oak has increased to 58.5% from 22.8%, and we will assume operatorship of Gray Oak in the second quarter of 2023. Simultaneously, our effective economic interest in DCP has been reduced to 13.2% from 28.3%. We received approximately \$522 million (US\$404 million) in cash proceeds and recorded an accounting gain of approximately \$1.1 billion (US\$832 million) in the Consolidated Statements of Earnings as a result of the transaction.

Acquisition of Tri Global Energy, LLC

On September 27, 2022, we acquired Tri Global Energy, LLC (TGE), a leading United States (US) renewable power project developer, for approximately US\$270 million in cash and assumed debt. The acquisition of TGE enhances our renewable power platform and further builds on our inventory of North American growth opportunities for wind and solar projects.

Athabasca Indigenous Investments Partnership

On October 5, 2022, we completed a transaction with Athabasca Indigenous Investments Limited Partnership (Aii), a newly created entity representing 23 First Nation and Métis communities, in which Aii acquired an 11.6% non-operating interest in seven Regional Oil Sands pipelines in northern Alberta for \$1.1 billion.

Increased Ownership in Cactus II Pipeline
On November 2, 2022, we acquired an additional 10.0% ownership in Cactus II Pipeline from Western Midstream Partners, L.P., for cash payment of $241 million (US$177 million), bringing our total non-operating ownership to 30.0%. Plains All-American Pipeline, L.P. remains the operator with a 70% ownership stake.

Woodfibre LNG Limited Partnership Agreement
On November 29, 2022, we finalized our partnership agreement with Pacific Energy Corporation Limited. We acquired, for cash payment of $533 million (US$392 million), an effective 30.0% interest in Woodfibre LNG Limited Partnership (Woodfibre), which will operate the 2.1 million tonnes per annum Woodfibre LNG facility located in Squamish, British Columbia (BC). The facility, via an interconnect with FortisBC Energy Inc., is an extension of the BC Pipeline System, which will supply gas to the facility under a 40-year transportation agreement.

GAS TRANSMISSION AND MIDSTREAM PROCEEDINGS
Texas Eastern Transmission
Texas Eastern Transmission, LP (Texas Eastern) filed two rate cases in the third quarter of 2021. These two rate proceedings have since been consolidated and settlement negotiations began during the first quarter of 2022. An uncontested settlement in principle was reached on July 7, 2022. Texas Eastern filed an uncontested Stipulation and Agreement on September 8, 2022 to resolve all issues from the rate proceedings. The Federal Energy Regulatory Commission (FERC) approved the Stipulation and Agreement on November 30, 2022, and the Stipulation and Agreement became effective on January 1, 2023.

Maritimes & Northeast Pipeline
The toll settlement agreement for the Canadian portion of our Maritimes & Northeast (M&N Canada) Pipeline system expired in December 2021. In December 2021, the Canada Energy Regulator (CER) approved interim tolls for M&N Canada effective January 1, 2022, which were based on the negotiated 2022 tolls in the 2022-2023 settlement agreement and unanimously supported by shippers. The 2022-2023 M&N Canada settlement agreement was approved by the CER in February 2022.

British Columbia Pipeline
The toll settlement agreement for our BC Pipeline system expired in December 2021. In December 2021, the CER approved interim tolls for BC Pipeline effective January 1, 2022. In the fourth quarter of 2022, a five-year 2022-2026 BC Pipeline settlement agreement was approved by shippers and subsequently approved as filed by the CER.

GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS
2022 Rate Application
Enbridge Gas Inc.'s (Enbridge Gas) rate applications are filed in two phases. In June 2021, Enbridge Gas filed Phase 1 of the application with the Ontario Energy Board (OEB) for the setting of rates for 2022 (the 2022 Application). The 2022 Application was filed in accordance with the parameters of Enbridge Gas' OEB approved Price Cap Incentive Regulation (IR) rate setting mechanism and represents the fourth year of a five-year term. In October 2021, the OEB approved a Phase 1 Settlement Proposal and Interim Rate Order effective January 1, 2022. In April 2022, the OEB issued its decision on Phase 2 of the 2022 Application filed in October 2021, addressing incremental capital module (ICM) funding requirements, under which $127 million of the requested capital funding was approved and incorporated into final rates, effective July 1, 2022.

2023 Rate Application
In June 2022, Enbridge Gas filed Phase 1 of the application with the OEB for the setting of rates for 2023 (the 2023 Application). The 2023 Application was filed in accordance with the parameters of Enbridge Gas' OEB approved Price Cap IR rate setting mechanism and represents the final year of a five-year term. In November 2022, the OEB approved the Phase 1 Settlement Proposal and Final Rate Order effective January 1, 2023. In addition, Enbridge Gas did not anticipate 2023 capital investments to require incremental funding during the final year of its current Price Cap IR term, and, as such, Enbridge Gas did not make a Phase 2 ICM request as part of the 2023 Application.

2024 Rebasing and Incentive Rate-Setting Mechanism Application
In October 2022, Enbridge Gas filed its application with the OEB to establish a 2024 through 2028 rate setting framework. The application and framework seek approval to establish 2024 base rates on a cost-of-service basis and to establish a price cap IR rate setting mechanism to be used for the remainder of the IR term (2025-2028). The OEB has determined it will hear the application in two phases, with Phase 1 addressing items that affect rates effective January 1, 2024, and Phase 2 addressing items that will affect rates subsequent to January 1, 2024. An OEB decision is expected on Phase 1 of the application in the second half of 2023.

Purchase Gas Variance
The Purchase Gas Variance Account (PGVA) captures the difference between actual and forecasted natural gas prices reflected in rates. Account balances are typically recovered or refunded over a prospective 12-month period through Quarterly Rate Adjustment Mechanism (QRAM) applications.

In March and June 2022, the OEB approved Enbridge Gas' April 1, 2022 and July 1, 2022 QRAM applications, respectively. Due to the significant increase in natural gas prices, the approvals have also included rate mitigation plans intended to ease bill impacts to ratepayers. Specifically, the approved rate mitigation plans extended the PGVA recovery period from 12 months to 24 months in both applications. As an additional mitigation measure, as part of the April 1, 2022 QRAM, a portion of the PGVA balance was deferred for recovery, which was subsequently approved for recovery as part of the July 1, 2022 QRAM. In September and December 2022, the October 1, 2022 and January 1, 2023 QRAM applications were filed and approved by the OEB with no adjustments to the prior period rate mitigation plans and did not include any additional rate mitigation measures.

As at December 31, 2022, Enbridge Gas' PGVA receivable balance was $434 million.

FINANCING UPDATE
We completed long-term debt issuances totaling US$3.2 billion and $3.4 billion during the year ended December 31, 2022, including $900 million of 10-year sustainability-linked medium-term notes in November 2022. We increased our credit facilities during our annual renewal process by approximately $640 million and also entered into new term loans with maturities ranging from 2023 to 2027 totaling approximately $3.2 billion.

Our 2022 financing activities have provided significant liquidity that we expect will enable us to fund our current portfolio of capital projects without requiring access to the capital markets for the next 12 months should market access be restricted or pricing be unattractive. Refer to *Liquidity and Capital Resources*.

As at December 31, 2022, after adjusting for the impact of floating-to-fixed interest rate swap hedges, approximately 6% of our total debt is exposed to floating rates. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 24. Risk Management and Financial Instruments* for more information on our interest rate hedging program.

NORMAL COURSE ISSUER BID

On January 4, 2023, we announced that the Toronto Stock Exchange (TSX) had approved our new normal course issuer bid (NCIB) to purchase for cancellation up to 27,938,163 of the outstanding common shares of Enbridge to an aggregate amount of up to $1.5 billion, subject to certain restrictions on the number of common shares that may be purchased on a single day. The NCIB follows on the termination of our prior NCIB, which expired on January 4, 2023.

Purchases under the NCIB may be made through the facilities of the TSX, the New York Stock Exchange and other designated exchanges and alternative trading systems commencing on January 6, 2023 and continuing until January 5, 2024, when the NCIB expires, or such earlier date on which Enbridge has either acquired the maximum number of common shares allowable under the NCIB or otherwise decided not to make any further repurchases under the NCIB. The maximum number of common shares that Enbridge may purchase for cancellation under the NCIB represents approximately 1.38% of the 2,024,890,423 common shares issued and outstanding as at December 23, 2022.

RESULTS OF OPERATIONS

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars, except per share amounts)			
Segment earnings/(loss) before interest, income taxes and depreciation and amortization[1]			
Liquids Pipelines	**8,364**	7,897	7,683
Gas Transmission and Midstream	**3,126**	3,671	1,087
Gas Distribution and Storage	**1,827**	2,117	1,748
Renewable Power Generation	**262**	508	523
Energy Services	**(417)**	(313)	(236)
Eliminations and Other	**(1,124)**	356	(113)
Earnings before interest, income taxes and depreciation and amortization[1]	**12,038**	14,236	10,692
Depreciation and amortization	**(4,317)**	(3,852)	(3,712)
Interest expense	**(3,179)**	(2,655)	(2,790)
Income tax expense	**(1,604)**	(1,415)	(774)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**65**	(125)	(53)
Preference share dividends	**(414)**	(373)	(380)
Earnings attributable to common shareholders	**2,589**	5,816	2,983
Earnings per common share attributable to common shareholders	**1.28**	2.87	1.48
Diluted earnings per common share attributable to common shareholders	**1.28**	2.87	1.48

1 Non-GAAP financial measures.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Year ended December 31, 2022 compared with year ended December 31, 2021

Earnings attributable to common shareholders decreased by $3,368 million due to certain infrequent or other non-operating factors, primarily explained by the following:

- a goodwill impairment of $2.5 billion relating to our Gas Transmission reporting unit;
- non-cash, net unrealized derivative fair value losses of $1,265 million ($964 million after-tax) in 2022, compared with unrealized gains of $197 million ($150 million after-tax) in 2021, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks;
- an asset impairment loss of $227 million ($173 million after-tax) to our Magic Valley Wind Farm (Magic Valley);

- an asset impairment loss of $183 million ($137 million after-tax) on the US and Canadian components of the interstate pipeline transportation system within the North Dakota System of our Bakken System;
- a transaction cost of $114 million in relation to our investment purchase in the Woodfibre LNG project;
- an impairment of $44 million ($34 million after-tax) for lease assets due to office relocation plans;
- an asset impairment loss of $40 million ($30 million after-tax) relating to MacKay River line within our Alberta Regional Oil Sands System;
- the absence in 2022 of a gain of $303 million ($298 million after-tax) from the sale of our investment in Noverco Inc. (Noverco); and
- the absence in 2022 of a $57 million ($43 million after-tax) property tax settlement received in 2021 related to the resolution of Minnesota property tax appeals for 2012-2018.

The factors above were partially offset by:
- a gain of $1,076 million ($732 million after-tax) on the closing of the joint venture merger transaction with P66 realigning our effective economic interests in Gray Oak and DCP;
- a gain of $118 million ($89 million after-tax) on Texas Eastern recorded to reflect a settlement with a transportation customer undergoing bankruptcy;
- a deferred tax benefit of $95 million recognized as a result of the reduced Pennsylvania state corporate income tax;
- a non-cash, net negative equity earnings adjustment of $10 million ($7 million after-tax) in 2022, compared to a net negative adjustment of $44 million ($33 million after-tax) in 2021 relating to our share of changes in the mark-to-market value of derivative financial instruments of our equity method investee, DCP;
- transition and transformation costs of $66 million ($50 million after-tax) in 2022, compared to $147 million ($112 million after-tax) in 2021; and
- the absence in 2022 of an impairment loss of $111 million ($83 million after-tax) to our investment in the PennEast Pipeline Company, LLC (PennEast) pipeline project.

The non-cash, unrealized derivative fair value gains and losses discussed above generally arise as a result of our comprehensive economic hedging program to mitigate foreign exchange and commodity price risks. This program creates volatility in reported short-term earnings through the recognition of unrealized non-cash gains and losses on derivative instruments used to hedge these risks. Over the long-term, we believe our hedging program supports the reliable cash flows and dividend growth upon which our investor value proposition is based.

After taking into consideration the factors above, the remaining $141 million increase in earnings attributable to common shareholders is primarily explained by the following significant business factors:
- higher throughput within our Liquids Pipelines segment driven by higher demand and incremental Line 3 Replacement (L3R) capacity that came into service October 2021;
- increased earnings within our Liquids Pipelines segment from the implementation of the full L3R surcharge when compared to the lower surcharge on the Canadian portion of the project in effect prior to October 2021, as well as from new US export assets acquired in October 2021;
- increased earnings from our Gas Transmission and Midstream segment primarily as a result of higher commodity prices benefiting our investments in DCP and Aux Sable, as well as higher contributions from projects placed into service in November 2021; and
- recognition of revenues attributable to the Texas Eastern rate case resulting from a FERC-approved Stipulation and Agreement; partially offset by
- the recognition of a provision against the interim Mainline International Joint Tariff (IJT) for barrels shipped for the full year in 2022, as compared to the barrels shipped in the second half of 2021 following the expiry of the Competitive Toll Settlement (CTS);

- higher interest expense primarily due to higher interest rates and higher average principal, as well as reduced capitalized interest associated with the US portion of the L3R Project placed into service in the fourth quarter of 2021;
- higher depreciation and amortization expense as a result of several projects placed into service in the fourth quarter of 2021, as well as for new US export assets acquired in October 2021; and
- higher income tax expense due to higher earnings, higher US minimum taxes, and the effect of rate-regulated accounting for income taxes.

REVENUES

We generate revenues from three primary sources: transportation and other services, gas distribution sales and commodity sales.

Transportation and other services revenues of $18.5 billion, $16.2 billion and $16.2 billion for the years ended December 31, 2022, 2021 and 2020, respectively, were earned from our crude oil and natural gas pipeline transportation businesses and also include power generation revenues from our portfolio of renewable and power generation assets. For our transportation assets operating under market-based arrangements, revenues are driven by volumes transported and the corresponding tolls for transportation services. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator and, in most cost-of-service based arrangements, are reflective of our cost to provide the service plus a regulator-approved rate of return.

Gas distribution sales revenues of $5.7 billion, $4.0 billion and $3.7 billion for the years ended December 31, 2022, 2021 and 2020, respectively, were recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are primarily driven by volumes delivered, which vary with weather and customer composition and utilization, as well as regulator-approved rates. The cost of natural gas is passed through to customers through rates and does not ultimately impact earnings due to its flow-through nature.

Commodity sales revenues of $29.2 billion, $26.9 billion and $19.3 billion for the years ended December 31, 2022, 2021 and 2020, respectively, were generated primarily through our Energy Services operations. Energy Services includes the contemporaneous purchase and sale of crude oil, natural gas, power and Natural Gas Liquids (NGL) to generate a margin, which is typically a small fraction of gross revenue. While sales revenue generated from these operations are impacted by commodity prices, net margins and earnings are relatively insensitive to commodity prices and reflect activity levels which are driven by differences in commodity prices between locations, grades and points in time, rather than on absolute prices. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year-to-year depending on market conditions and commodity prices.

Our revenues also include changes in unrealized derivative fair value gains and losses related to foreign exchange and commodity price contracts used to manage exposures from movements in foreign exchange rates and commodity prices. The mark-to-market accounting creates volatility and impacts the comparability of revenues in the short-term, but we believe over the long-term, the economic hedging program supports reliable cash flows.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**8,364**	7,897	7,683

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $710 million due to certain infrequent or other non-operating factors, primarily explained by the following:
- non-cash, net unrealized losses of $183 million in 2022, compared with unrealized gains of $120 million in 2021, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks;
- total asset impairment loss of $183 million on the US and Canadian components of the interstate pipeline transportation system within the North Dakota System of our Bakken System;
- an asset impairment loss of $40 million relating to MacKay River line within our Alberta Regional Oil Sands System; and
- the absence in 2022 of a $57 million property tax settlement received in 2021 related to the resolution of Minnesota property tax appeals for 2012-2018.

After taking into consideration the factors above, the remaining $1.2 billion increase is primarily explained by the following significant business factors:
- higher Mainline System ex-Gretna average throughput of 3.0 million barrels per day (mmbpd) in 2022 as compared to 2.8 mmbpd in 2021 driven by higher demand and incremental L3R capacity that came into service October 2021;
- implementation of the full L3R surcharge when compared to the lower surcharge on the Canadian portion of the project in effect prior to October 2021;
- higher contributions from the Gulf Coast and Mid-Continent System due primarily to the acquisition of the Enbridge Ingleside Energy Center and related assets in the fourth quarter of 2021 in addition to the increased effective economic interest in the Gray Oak pipeline during the third quarter of 2022 and higher volumes from Flanagan South Pipeline;
- higher contributions from the Bakken System due to higher volumes; and
- the favorable effect of translating US dollar EBITDA at a higher average exchange rate in 2022 compared to the same period in 2021; partially offset by
- the recognition of a provision against the interim Mainline IJT for barrels shipped for the full year in 2022, as compared to the barrels shipped in the second half of 2021 following the expiry of the CTS;
- lower contributions from the Seaway Crude Pipeline System, as well as from the Cushing and Hardisty storage assets as a result of lower demand; and
- higher power costs as a result of increased volumes and power prices.

GAS TRANSMISSION AND MIDSTREAM

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**3,126**	3,671	1,087

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $1.1 billion due to certain infrequent or other non-operating factors primarily explained by the following:
- a goodwill impairment of $2.5 billion; partially offset by
- a gain of $1,076 million on the closing of the joint venture merger transaction with P66 realigning our effective economic interests in Gray Oak and DCP;
- the absence of the $111 million impairment loss in 2021 to our investment in the PennEast pipeline project after a decision by project partners to cease development;
- a gain of $118 million on Texas Eastern recorded for a customer bankruptcy settlement; and
- a non-cash, net negative equity earnings adjustment of $10 million in 2022, compared to a net negative adjustment of $44 million in 2021 relating to our share of changes in the mark-to-market value of derivative financial instruments of our equity method investees, DCP and Aux Sable.

After taking into consideration the factors above, we saw a $567 million increase, primarily explained by the following significant business factors:
- higher commodity prices benefiting our DCP and Aux Sable joint ventures;
- the favorable effect of translating US dollar EBITDA at a higher average exchange rate in 2022 compared to the same period in 2021;
- recognition of revenues attributable to the Texas Eastern rate case resulting from a FERC-approved Stipulation and Agreement;
- contributions from the T-South and Spruce Ridge expansion projects, the Cameron and Middlesex Extension projects, and the Appalachia to Market project after service commenced in the fourth quarter of 2021;
- higher AECO-Chicago basis differential and lower costs benefiting earnings from our investment in Alliance; and
- recognition of revenues attributable to the BC Pipeline rate settlement; partially offset by
- higher operating costs; and
- a reduction in earnings from our investment in DCP as a result of our decreased effective economic interest due to the joint venture merger transaction with P66 that closed during the third quarter of 2022.

GAS DISTRIBUTION AND STORAGE

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**1,827**	2,117	1,748

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $293 million due to certain infrequent or other non-operating factors primarily explained by the absence of a gain of $303 million resulting from the sale of our investment in Noverco in 2021.

After taking into consideration the factors above, the remaining $3 million increase is primarily explained by the following significant business factors:

- higher distribution charges at Enbridge Gas resulting from increases in rates and customer base, as well as higher demand in the contract market;
- when compared with the normal weather forecast embedded in rates, colder than normal weather in 2022 positively impacted Enbridge Gas 2022 EBITDA by approximately $17 million while warmer than normal weather in 2021 negatively impacted 2021 EBITDA by approximately $55 million; and
- lower pension related costs; partially offset by
- the absence of earnings from Noverco due to the sale of our minority investment in December 2021; and
- higher operating costs at Enbridge Gas largely driven by higher employee costs and higher maintenance and integrity spend.

RENEWABLE POWER GENERATION

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**262**	508	523

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $272 million due to certain infrequent or non-operating factors, primarily explained by an impairment loss of $227 million to Magic Valley.

After taking into consideration the negative factor above, the remaining $26 million increase is primarily explained by the following significant business factors:

- higher energy pricing at European offshore wind facilities;
- stronger wind resources at Canadian and US onshore wind facilities; and
- the absence in 2022 of the adverse effects from the major winter storm in Texas during February 2021; partially offset by
- the absence in 2022 of a promote fee received in the first quarter of 2021 associated with the closing of the sale of 49% of our interest in three European offshore wind projects to Canada Pension Plan Investment Board.

ENERGY SERVICES

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization[1]	**(417)**	(313)	(236)

1 Non-GAAP financial measure.

EBITDA from Energy Services is dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $100 million due to certain non-operating factors, primarily explained by non-cash, unrealized losses of $27 million in 2022, compared with unrealized gains of $53 million in 2021, reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions, as well as to manage the exposure to movements in commodity prices.

After taking into consideration the factor above, the remaining $4 million decrease is primarily explained by the following significant business factors:

- more pronounced market structure backwardation than in 2021 and significant compression of location differentials in certain markets; partially offset by
- the absence of adverse impacts from the major winter storm experienced across the US Midwest during February 2021.

ELIMINATIONS AND OTHER

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization[1]	**(1,124)**	356	(113)

1 Non-GAAP financial measure.

Eliminations and Other includes operating and administrative costs that are not allocated to business segments, the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiaries. Eliminations and Other also includes the impact of new business development activities and corporate investments.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $1.2 billion due to certain infrequent or non-operating factors, primarily explained by:

- non-cash, net unrealized losses of $1,090 million in 2022, compared with unrealized gains of $55 million in 2021, reflecting the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk;
- a transaction cost of $114 million in relation to our investment purchase in the Woodfibre LNG project; and
- an impairment of $44 million for lease assets due to office relocation plans in Houston.

After taking into consideration the non-operating factors above, we saw a $239 million decrease in EBITDA that is primarily explained by:

- the lower realized foreign exchange gains on hedge settlements in 2022; and
- higher Operating and administrative expense largely driven by an increase in employee costs.

GROWTH PROJECTS - COMMERCIALLY SECURED PROJECTS

The following table summarizes the status of our significant commercially secured projects, organized by business segment:

		Enbridge's Ownership Interest	Estimated Capital Cost[1]	Expenditures to Date[2]	Status[2]	Expected In-Service Date
(Canadian dollars, unless stated otherwise)						
GAS TRANSMISSION AND MIDSTREAM						
1.	Vito Gas & Oil	100 %	US$0.3 billion	US$0.2 billion	Complete	In-service
2.	Texas Eastern Venice Extension Project	100 %	US$0.4 billion	US$0.1 billion	Pre-construction	2023 - 2024
3.	Texas Eastern Modernization	100 %	US$0.4 billion	No significant expenditures to date	Pre-construction	2024 - 2025
4.	T-North Expansion	100 %	$1.2 billion	No significant expenditures to date	Pre-construction	2026
5.	Woodfibre LNG Project[3]	30 %	US$1.5 billion	No significant expenditures to date	Pre-construction	2027
6.	T-South Expansion	100 %	$3.6 billion	No significant expenditures to date	Pre-construction	2028
RENEWABLE POWER GENERATION						
7.	Saint-Nazaire France Offshore Wind Project[4]	25.5 %	$0.9 billion (€0.6 billion)	$0.9 billion (€0.6 billion)	Complete	In-service
8.	Fécamp Offshore Wind Project[5]	17.9 %	$0.7 billion (€0.5 billion)	$0.4 billion (€0.3 billion)	Under construction	2023
9.	Calvados Offshore Wind Project[4]	21.7 %	$0.9 billion (€0.6 billion)	$0.3 billion (€0.2 billion)	Under construction	2025

1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.
2 Expenditures to date and status of the project are determined as at December 31, 2022.
3 Our equity contribution is US$0.9 billion, with the remainder financed through non-recourse project level debt.
4 Our equity contribution is $0.2 billion for each project, with the remainder of each project financed through non-recourse project level debt.
5 Our equity contribution is $0.1 billion, with the remainder financed through non-recourse project level debt.

Risks related to the development and completion of growth projects are described under Part I. *Item 1A. Risk Factors.*

GAS TRANSMISSION AND MIDSTREAM
The following commercially secured growth project was placed into service in 2022:

- **Vito Gas & Oil** – Two pipelines connecting Vito Floating Production System from Mississippi Canyon to the Shell Mars System platform in West Delta 143 and Olympic Gas. Enbridge designed, fabricated, installed, and now operates, the Vito Gas & Oil export pipeline system consisting of pipeline and steel catenary riser.

The following commercially secured growth projects are currently in various stages of construction:

- **Texas Eastern Venice Extension Project** – A reversal and expansion of Texas Eastern's Line 40 from its existing New Roads compressor station to a new delivery point with the proposed Gator Express pipeline just south of Texas Eastern's Larose compressor station. The project is expected to deliver 1.5 billion cubic feet per day (bcf/d) of natural gas to Venture Global Plaquemines LNG, LLC's LNG export facility located in Plaquemines Parish, Louisiana and is underpinned by long-term take or pay contracts.

- **Texas Eastern Modernization –** This program is the modernization of compression facilities in Pennsylvania and New Jersey to increase safety and reliability and reduce associated greenhouse gas emissions at multiple sites on our Texas Eastern system. The program will be completed in stages over a period of years beginning in 2024.

- **T-North Expansion** – An expansion of Westcoast Energy Inc.'s (Westcoast) BC Pipeline in northern BC that includes pipeline looping, additional compressor units and other ancillary station modifications to support 535 million cubic feet per day (MMcf/d) of additional capacity. The project will be underpinned by a cost-of-service commercial model with a target in-service date of 2026.

- **Woodfibre LNG Project** – Construction of liquefaction and floating storage facilities in Squamish, BC, as well as an expansion of the BC Pipeline System. The project is expected to be placed into service in 2027.

- **T-South Expansion** – An expansion of Westcoast's BC Pipeline's T-South section that includes pipeline looping, additional compressor units and other ancillary station modifications to support 300 MMcf/d of additional capacity. The project is expected to be placed in service in 2028 and will be underpinned by a cost-of-service commercial model.

RENEWABLE POWER GENERATION

The following commercially secured growth projects were placed into service in 2022:

- **Saint-Nazaire Offshore Wind Project –** A wind project located off the west coast of France that is expected to generate approximately 480 megawatts (MW). Project revenues are backed by a 20-year fixed price power purchase agreement (PPA) with added power production protection.

The following commercially secured growth projects are expected to be placed into service from 2023 to 2025:

- **Fécamp Offshore Wind Project –** An offshore wind project that will be comprised of 71 wind turbines located off the northwest coast of France and is expected to generate approximately 500 MW. Project revenues are underpinned by a 20-year fixed price PPA.

- **Calvados Offshore Wind Project –** An offshore wind project located off the northwest coast of France that is expected to generate approximately 448 MW. Project revenues are underpinned by a 20-year fixed price PPA.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following project has been announced by us, but has not yet met our criteria to be classified as commercially secured:

GAS TRANSMISSION AND MIDSTREAM

- **Valley Crossing Expansion Project** – On January 10, 2022, we executed a precedent agreement with Texas LNG Brownsville LLC (Texas LNG) under which, via an expansion of our Valley Crossing Pipeline, we will provide 0.72 bcf/d firm transportation capacity to Texas LNG's proposed LNG liquefaction and export facility in the Port of Brownsville, Texas for a term of at least 20 years. Expansion of the pipeline will be subject to Texas LNG's export facility reaching a final investment decision.

We also have a portfolio of additional projects under development that have not yet progressed to the point of securement.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to our growth strategy, particularly in light of the significant number and size of capital projects currently secured or under development. Access to timely funding from capital markets could be limited by factors outside our control including, but not limited to, financial market volatility resulting from economic and political events both inside and outside North America. To mitigate such risks, we actively manage financial plans and strategies to ensure we maintain sufficient liquidity to meet routine operating and future capital requirements. In the near term, we generally expect to utilize cash from operations together with commercial paper issuance and/or credit facility draws and the proceeds of capital market offerings to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. We target to maintain sufficient liquidity through securement of committed credit facilities with a diversified group of banks and financial institutions to enable us to fund all anticipated requirements for approximately one year without accessing the capital markets.

Material contractual obligations arising in the normal course of business primarily consist of long-term contracts, annual debt maturities and related interest obligations, rights-of-way and leases. See Part II. *Item 8. Financial Statements and Supplementary data - Note 18 - Debt* and *Note 27 - Leases* for amounts outstanding at December 31, 2022, related to debt and leases.

Long-term contracts are contracts that we have signed for the purchase of services, pipe and other materials totaling $7.9 billion which are expected to be paid over the next five years. Long-term contracts primarily consists of the following purchase obligations: firm capacity payments for natural gas and crude oil transportation and storage contracts, natural gas purchase commitments, service and product purchase obligations and power commitments.

Our financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives. Our current financing plan does not include any issuances of common equity.

CAPITAL MARKET ACCESS

We ensure ready access to capital markets, subject to market conditions, through maintenance of shelf prospectuses that allow for issuance of long-term debt, equity and other forms of long-term capital when market conditions are attractive. In accordance with our funding plan, we completed the following long-term debt issuances totaling US$3.2 billion and $3.4 billion in 2022:

Entity	Issuance date	Type of issuance	Amount
(in millions of Canadian dollars, unless stated otherwise)			
Enbridge Inc.	January 2022	Fixed-to-fixed subordinated notes	$750
Enbridge Inc.	February 2022	Floating rate senior notes	US$600
Enbridge Inc.	February 2022	Senior notes	US$900
Enbridge Inc.	September 2022	Fixed-to-fixed subordinated notes	US$1,100
Enbridge Inc.	November 2022	Medium-term notes	$1,100
Enbridge Inc.	November 2022	Sustainability-linked medium-term notes	$900
Enbridge Gas Inc.	August 2022	Medium-term notes	$650
Texas Eastern Transmission LP	December 2022	Senior notes	US$600

Credit Facilities, Ratings and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain ready access to funds through committed bank credit facilities and actively manage our bank funding sources to optimize pricing and other terms. The following table provides details of our committed credit facilities, inclusive of term loans, at December 31, 2022:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2023-2027	**10,987**	**7,984**	**3,003**
Enbridge (U.S.) Inc.	2024-2027	**8,604**	**4,199**	**4,405**
Enbridge Pipelines Inc.	2024	**2,000**	**312**	**1,688**
Enbridge Gas Inc.	2024	**2,000**	**2,000**	**—**
Total committed credit facilities		**23,591**	**14,495**	**9,096**

1 Maturity date is inclusive of the one-year term out option for certain credit facilities.
2 Includes facility draws and commercial paper issuances that are back-stopped by credit facilities.

On February 10, 2022, we renewed our three year $1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

On May 17, 2022, we entered into a three year term loan with a syndicate of Japanese banks for approximately $806 million (¥84.8 billion), which will mature in May 2025 and replaces the approximately $499 million (¥52.5 billion) term loan that matured in May 2022. Additionally, on May 24, 2022, we entered into a 364-day term loan for approximately $1.9 billion, which will mature in May 2023.

On June 23, 2022, we renewed approximately $5.5 billion of our 364-day extendible credit facilities to July 2024, which includes a one-year term out provision from July 2023.

In July and August 2022, we renewed $12.7 billion of our credit facilities, extending the maturity dates of our 364-day credit facilities to July 2024, inclusive of a one year term out provision from July 2023, and our five year facilities out to July 2027. As a part of the renewals, we increased our credit facilities by approximately $640 million.

On December 16, 2022, Enbridge (U.S.) Inc. entered into a five year delay draw term loan in support of solar self-power projects for approximately $479 million, which will mature in December 2027.

In addition to the committed credit facilities noted above, we maintain $1.3 billion of uncommitted demand letter of credit facilities, of which $689 million was unutilized as at December 31, 2022. As at December 31, 2021, we had $1.3 billion of uncommitted demand letter of credit facilities, of which $854 million was unutilized.

As at December 31, 2022, our net available liquidity totaled $10.0 billion (2021 - $6.5 billion), consisting of available credit facilities of $9.1 billion (2021 - $6.2 billion) and unrestricted Cash and cash equivalents of $861 million (2021 - $286 million) as reported in the Consolidated Statements of Financial Position.

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions, whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2022, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

Cash flow growth, ready access to liquidity from diversified sources and a stable business model have enabled us to manage our credit profile. We actively monitor and manage key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. In 2022, our credit ratings with DBRS Morningstar, Fitch Ratings, Moody's Investor Services, Inc. and Standard & Poor's were all affirmed. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to EBITDA.

There are no material restrictions on our cash. Total Restricted cash of $46 million, as reported in the Consolidated Statements of Financial Position, primarily includes cash collateral and future pipeline abandonment costs collected and held in trust. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative use by us.

Excluding current maturities of long-term debt, as at December 31, 2022 and 2021, we had a negative working capital position of $2.1 billion and $3.1 billion, respectively. In both periods, the major contributing factor to the negative working capital position was the current liabilities associated with our growth capital program.

To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due.

SOURCES AND USES OF CASH

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating activities	**11,230**	9,256	9,781
Investing activities	**(5,270)**	(10,657)	(5,177)
Financing activities	**(5,428)**	1,236	(4,770)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**55**	(5)	(20)
Net change in cash and cash equivalents and restricted cash	**587**	(170)	(186)

Significant sources and uses of cash for the years ended December 31, 2022 and 2021 are summarized below:

Operating Activities
Typically, the primary factors impacting cash flow from operating activities year-over-year include changes in our operating assets and liabilities in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within our business segments, the timing of tax payments, as well as timing of cash receipts and payments generally. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 29. Changes in Operating Assets and Liabilities.* Cash provided by operating activities is also impacted by changes in earnings and certain infrequent or other non-operating factors, as discussed under *Results of Operations.*

Investing Activities
Cash used in investing activities primarily relates to capital expenditures to execute our capital program, which is further described in *Growth Projects - Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements.

A summary of additions to property, plant and equipment for the years ended December 31, 2022, 2021 and 2020 is set out below:

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Liquids Pipelines	**1,418**	4,051	2,032
Gas Transmission and Midstream	**1,647**	2,353	2,066
Gas Distribution and Storage	**1,499**	1,343	1,134
Renewable Power Generation	**50**	16	81
Energy Services	**—**	1	2
Eliminations and Other	**33**	54	90
Total capital expenditures	**4,647**	7,818	5,405

2022
The decrease in cash used in investing activities primarily resulted from the following factors:

- lower capital expenditures due to the US L3R Program that was placed into service in the fourth quarter of 2021;
- lower cash outflows related to acquisitions in 2022 when compared to 2021; and
- proceeds received from the completion of a joint venture merger transaction for DCP Midstream LLC in August 2022.

The factors above were partially offset by:

- the absence in 2022 of proceeds received from dispositions in 2021 related to sale of our interest in Noverco in December 2021; and
- increased investments held by our wholly-owned captive insurance subsidiaries.

2021
The increase in cash used in investing activities primarily resulted from our acquisition of Moda Midstream Operating, LLC and higher capital expenditures related to the completion of the US L3R Program in 2021, partially offset by higher proceeds received from dispositions in 2021 compared to 2020 due to the sale of our interest in Noverco.

Financing Activities
Cash used in financing activities primarily relates to issuances and repayments of external debt, as well as transactions with our common and preference shareholders relating to dividends, share issuances, share redemptions and common share repurchases under our NCIB. Cash flow from financing activities is also impacted by changes in distributions to, and contributions from, noncontrolling interests.

2022
The increase in cash used in financing activities primarily resulted from the following factors:

- net commercial paper and credit facility repayments in 2022 when compared to draws in 2021;
- higher long-term debt repayments along with lower long-term debt issuances in 2022 when compared to 2021;
- the redemption of Preference Shares, Series 17 and Series J in the first and second quarters of 2022, respectively;
- the repurchase and cancellation of 2,737,965 common shares under our NCIB for approximately $151 million in 2022; and
- increased common share dividend payments primarily due to the increase in our common share dividend rate.

The factors above were partially offset by:

- proceeds received from the sale of a non-operating interest in seven pipelines from our Regional Oil Sands System in October 2022;
- the absence in 2022 of the redemption of Westcoast's preferred shares in the first quarter of 2021; and
- higher short-term borrowings in 2022 when compared to 2021.

2021
The increase in cash provided by financing activities primarily resulted from increased issuances of long-term debt, commercial paper and credit facility draws and short-term borrowings, along with lower repayments of long-term debt in 2021 when compared to 2020.

The factors above were partially offset by the redemption of Westcoast's preferred shares in 2021 and increased common share dividend payments primarily due to the increase in our common share dividend rate.

OFF-BALANCE SHEET ARRANGEMENTS

We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties and can include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Please see Part II. *Item 8. Financial Statements and Supplementary Data - Note 32. Guarantees* for further discussion of guarantee arrangements.

We do not have material off-balance sheet financing entities or structures, except for guarantee arrangements and financings entered into by our equity investments. For additional information on these commitments, please refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 31. Commitments and Contingencies* and *Note 12. Variable Interest Entities.*

We do not have material off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

PREFERENCE SHARE ISSUANCES

Characteristics of our outstanding preference shares are as follows:

	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars, unless otherwise stated)					
Preference Shares, Series A	5.50 %	$1.37500	$25	—	—
Preference Shares, Series B[5]	5.20 %	$1.30052	$25	June 1, 2027	Series C
Preference Shares, Series D	4.46 %	$1.11500	$25	March 1, 2023	Series E
Preference Shares, Series F	4.69 %	$1.17224	$25	June 1, 2023	Series G
Preference Shares, Series H	4.38 %	$1.09400	$25	September 1, 2023	Series I
Preference Shares, Series L[6]	5.86 %	US$1.46448	US$25	September 1, 2027	Series M
Preference Shares, Series N	5.09 %	$1.27152	$25	December 1, 2023	Series O
Preference Shares, Series P	4.38 %	$1.09476	$25	March 1, 2024	Series Q
Preference Shares, Series R	4.07 %	$1.01825	$25	June 1, 2024	Series S
Preference Shares, Series 1	5.95 %	US$1.48728	US$25	June 1, 2023	Series 2
Preference Shares, Series 3	3.74 %	$0.93425	$25	September 1, 2024	Series 4
Preference Shares, Series 5	5.38 %	US$1.34383	US$25	March 1, 2024	Series 6
Preference Shares, Series 7	4.45 %	$1.11224	$25	March 1, 2024	Series 8
Preference Shares, Series 9	4.10 %	$1.02424	$25	December 1, 2024	Series 10
Preference Shares, Series 11	3.94 %	$0.98452	$25	March 1, 2025	Series 12
Preference Shares, Series 13	3.04 %	$0.76076	$25	June 1, 2025	Series 14
Preference Shares, Series 15	2.98 %	$0.74576	$25	September 1, 2025	Series 16
Preference Shares, Series 19	4.90 %	$1.22500	$25	March 1, 2023	Series 20

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board of Directors. With the exception of Preference Shares, Series A, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Preference Shares, Series 19 contain a feature where the fixed dividend rate, when reset every five years, will not be less than 4.90%. No other series of Preference Shares has this feature.*

2 *Preference Shares, Series A may be redeemed any time at our option. For all other series of preference shares, we may at our option, redeem all or a portion of the outstanding preference shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.*

4 *With the exception of Preference Shares, Series A, after the redemption and conversion option dates, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/number of days in year) x Three-Month Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), or 3.2% (Series 20); or US$25 x (number of days in quarter/number of days in year) x Three-Month US Government treasury bill rate + 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).*

5 *The quarterly dividend per share paid on Preference Shares, Series B was increased to $0.32513 from $0.21340 on June 1, 2022 due to reset of the annual dividend on June 1, 2022. On June 1, 2022, all outstanding Preference Shares, Series C were converted to Preference Shares, Series B.*

6 *The quarterly dividend per share paid on Preference Shares, Series L was increased to US$0.36612 from US$0.30993 on September 1, 2022, due to reset of the annual dividend on September 1, 2022.*

PREFERENCE SHARE REDEMPTIONS

On March 1, 2022, we redeemed our $750 million outstanding Cumulative Redeemable Minimum Rate Reset Preference Shares, Series 17. On June 1, 2022, we also redeemed our US$200 million outstanding Cumulative Redeemable Preference Shares, Series J. Dividends are cumulative, payable quarterly and are included in Preference share dividends in the Consolidated Statements of Earnings.

DIVIDENDS

We have paid common share dividends in every year since we became a publicly traded company in 1953. In November 2022, we announced a 3.2% increase in our quarterly dividend to $0.88750 per common share, or $3.55 annualized, effective with the dividend payable on March 1, 2023, thereby declaring a dividend increase for 28 straight years.

For the years ended December 31, 2022 and 2021, total dividends paid were $7.0 billion and $6.8 billion, respectively, all of which were paid in cash and reflected in financing activities.

On November 29, 2022, our Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2023 to shareholders of record on February 15, 2023.

	Dividend per share
Common Shares[1]	$0.88750
Preference Shares, Series A	$0.34375
Preference Shares, Series B[2]	$0.32513
Preference Shares, Series D	$0.27875
Preference Shares, Series F	$0.29306
Preference Shares, Series H	$0.27350
Preference Shares, Series L[3]	US$0.36612
Preference Shares, Series N	$0.31788
Preference Shares, Series P	$0.27369
Preference Shares, Series R	$0.25456
Preference Shares, Series 1	US$0.37182
Preference Shares, Series 3	$0.23356
Preference Shares, Series 5	US$0.33596
Preference Shares, Series 7	$0.27806
Preference Shares, Series 9	$0.25606
Preference Shares, Series 11	$0.24613
Preference Shares, Series 13	$0.19019
Preference Shares, Series 15	$0.18644
Preference Shares, Series 19	$0.30625

1 The quarterly dividend per common share was increased 3.2% to $0.8875 from $0.860, effective March 1, 2023.
2 The quarterly dividend per share paid on Preference Shares Series B was increased to $0.32513 from $0.21340 on June 1, 2022, due to reset of the annual dividend on June 1, 2022 and every five years thereafter. Following the date of conversion of Preference Shares Series C, on June 1, 2022 all outstanding Preference Shares Series C were converted to Preference Shares Series B.
3 The quarterly dividend per share paid on Series L was increased to US$0.36612 from US$0.30993 on September 1, 2022, due to reset of the annual dividend on September 1, 2022, and every five years thereafter.

SUMMARIZED FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, Spectra Energy Partners, LP (SEP) and Enbridge Energy Partners, L.P. (EEP) (the Partnerships), pursuant to which Enbridge fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations of the Partnerships with respect to the outstanding series of notes issued under the respective indentures of the Partnerships. Concurrently, the Partnerships entered into a subsidiary guarantee agreement pursuant to which they fully and unconditionally guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. The Partnerships have also entered into supplemental indentures with Enbridge pursuant to which the Partnerships have issued full and unconditional guarantees, on a senior unsecured basis, of senior notes issued by Enbridge subsequent to January 22, 2019. As a result of the guarantees, holders of any of the outstanding guaranteed notes of the Partnerships (the Guaranteed Partnership Notes) are in the same position with respect to the net assets, income and cash flows of Enbridge as holders of Enbridge's outstanding guaranteed notes (the Guaranteed Enbridge Notes), and vice versa. Other than the Partnerships, Enbridge subsidiaries (including the subsidiaries of the Partnerships, collectively, the Subsidiary Non-Guarantors), are not parties to the subsidiary guarantee agreement and have not otherwise guaranteed any of Enbridge's outstanding series of senior notes.

Consenting SEP notes and EEP notes under Guarantee

SEP Notes[1]	EEP Notes[2]
4.750% Senior Notes due 2024	5.875% Notes due 2025
3.500% Senior Notes due 2025	5.950% Notes due 2033
3.375% Senior Notes due 2026	6.300% Notes due 2034
5.950% Senior Notes due 2043	7.500% Notes due 2038
4.500% Senior Notes due 2045	5.500% Notes due 2040
	7.375% Notes due 2045

1 As at December 31, 2022, the aggregate outstanding principal amount of SEP notes was approximately US$3.2 billion.
2 As at December 31, 2022, the aggregate outstanding principal amount of EEP notes was approximately US$2.4 billion.

Enbridge Notes under Guarantees

USD Denominated[1]	CAD Denominated[2]
Floating Rate Senior Notes due 2023	3.940% Senior Notes due 2023
Floating Rate Senior Notes due 2024	3.940% Senior Notes due 2023
4.000% Senior Notes due 2023	3.950% Senior Notes due 2024
0.550% Senior Notes due 2023	2.440% Senior Notes due 2025
3.500% Senior Notes due 2024	3.200% Senior Notes due 2027
2.150% Senior Notes due 2024	5.700% Senior Notes due 2027
2.500% Senior Notes due 2025	6.100% Senior Notes due 2028
2.500% Senior Notes due 2025	2.990% Senior Notes due 2029
4.250% Senior Notes due 2026	7.220% Senior Notes due 2030
1.600% Senior Notes due 2026	7.200% Senior Notes due 2032
3.700% Senior Notes due 2027	6.100% Sustainability-Linked Senior Notes due 2032
3.125% Senior Notes due 2029	3.100% Sustainability-Linked Senior Notes due 2033
2.500% Sustainability-Linked Senior Notes due 2033	5.570% Senior Notes due 2035
4.500% Senior Notes due 2044	5.750% Senior Notes due 2039
5.500% Senior Notes due 2046	5.120% Senior Notes due 2040
4.000% Senior Notes due 2049	4.240% Senior Notes due 2042
3.400% Senior Notes due 2051	4.570% Senior Notes due 2044
	4.870% Senior Notes due 2044
	4.100% Senior Notes due 2051
	6.510% Senior Notes due 2052
	4.560% Senior Notes due 2064

1 As at December 31, 2022, the aggregate outstanding principal amount of the Enbridge US dollar denominated notes was approximately US$11.0 billion.
2 As at December 31, 2022, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $10.2 billion.

Rule 3-10 of the US Securities and Exchange Commission's (SEC) Regulation S-X provides an exemption from the reporting requirements of the Securities Exchange Act of 1934, as amended (the Exchange Act) for fully consolidated subsidiary issuers of guaranteed securities and subsidiary guarantors and allows for summarized financial information in lieu of filing separate financial statements for each of the Partnerships.

The following Summarized Combined Statement of Earnings and the Summarized Combined Statements of Financial Position combines the balances of EEP, SEP and Enbridge.

Summarized Combined Statement of Earnings

Year ended December 31,	**2022**
(millions of Canadian dollars)	
Operating loss	**(179)**
Earnings	**1,921**
Earnings attributable to common shareholders	**1,507**

Summarized Combined Statements of Financial Position

December 31,	**2022**	2021
(millions of Canadian dollars)		
Cash and cash equivalents	**425**	12
Accounts receivable from affiliates	**2,486**	3,442
Short-term loans receivable from affiliates	**5,232**	4,947
Other current assets	**969**	593
Long-term loans receivable from affiliates	**43,873**	51,983
Other long-term assets	**4,111**	3,732
Accounts payable to affiliates	**1,375**	1,982
Short-term loans payable to affiliates	**1,745**	2,891
Other current liabilities	**8,752**	8,110
Long-term loans payable to affiliates	**37,626**	41,370
Other long-term liabilities	**47,447**	41,353

The Guaranteed Enbridge Notes and the Guaranteed Partnership Notes are structurally subordinated to the indebtedness of the Subsidiary Non-Guarantors in respect of the assets of those Subsidiary Non-Guarantors.

Under US bankruptcy law and comparable provisions of state fraudulent transfer laws, a guarantee can be voided, or claims may be subordinated to all other debts of that guarantor if, among other things, the guarantor, at the time the indebtedness evidenced by its guarantee or, in some states, when payments become due under the guarantee:

- received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee and was insolvent or rendered insolvent by reason of such incurrence;
- was engaged in a business or transaction for which the guarantor's remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

The guarantees of the Guaranteed Enbridge Notes contain provisions to limit the maximum amount of liability that the Partnerships could incur without causing the incurrence of obligations under the guarantee to be a fraudulent conveyance or fraudulent transfer under US federal or state law.

Each of the Partnerships is entitled to a right of contribution from the other Partnership for 50% of all payments, damages and expenses incurred by that Partnership in discharging its obligations under the guarantees for the Guaranteed Enbridge Notes.

Under the terms of the guarantee agreement and applicable supplemental indentures, the guarantees of either of the Partnerships of any Guaranteed Enbridge Notes will be unconditionally released and discharged automatically upon the occurrence of any of the following events:

- any direct or indirect sale, exchange or transfer, whether by way of merger, sale or transfer of equity interests or otherwise, to any person that is not an affiliate of Enbridge, of any of Enbridge's direct or indirect limited partnership of other equity interests in that Partnership as a result of which the Partnership ceases to be a consolidated subsidiary of Enbridge;
- the merger of that Partnership into Enbridge or the other Partnership or the liquidation and dissolution of that Partnership;
- the repayment in full or discharge or defeasance of those Guaranteed Enbridge Notes, as contemplated by the applicable indenture or guarantee agreement;
- with respect to EEP, the repayment in full or discharge or defeasance of each of the consenting EEP notes listed above;
- with respect to SEP, the repayment in full or discharge or defeasance of each of the consenting SEP notes listed above; or
- with respect to any series of Guaranteed Enbridge Notes, with the consent of holders of at least a majority of the outstanding principal amount of that series of Guaranteed Enbridge Notes.

The guarantee obligations of Enbridge will terminate with respect to any series of Guaranteed Partnership Notes if that series is discharged or defeased.

The Partnerships also guarantee the obligations of Enbridge under its existing credit facilities**.**

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES
Line 5 Easement (Bad River Band)
On July 23, 2019, the Bad River Band of the Lake Superior Tribe of Chippewa Indians (the Band) filed a complaint in the United States District Court for the Western District of Wisconsin (the Court) over our Line 5 pipeline and right-of-way across the Bad River Reservation (the Reservation). Only a small portion of the total easements across 12 miles of the Reservation are at issue. The Band alleges that our continued use of Line 5 to transport crude oil and related liquids across the Reservation is a public nuisance under federal and state law and that the pipeline is in trespass on certain tracts of land in which the Band possesses ownership interests. The complaint seeks an Order prohibiting us from using Line 5 to transport crude oil and related liquids across the Reservation and requiring removal of the pipeline from the Reservation. Subsequently amended versions of the complaint also seek recovery of profits-based damages based on an unjust enrichment theory. Enbridge has responded to each claim in the initial and amended complaints with an answer, defenses and counterclaims.

On August 29, 2022, the Government of Canada released a statement formally invoking the dispute settlement provisions of the 1977 Transit Pipelines Treaty in respect of this litigation; reiterating its concerns about the uninterrupted transmission of hydrocarbons through Line 5. On September 7, 2022, the Court issued a decision on cross-motions for summary judgment. The Court determined that the Band's nuisance claim raised factual issues that could not be resolved on summary judgment. The Court further determined that Enbridge is in trespass on 12 parcels on the Reservation and that the Band is entitled to some measure of profits-based damages and to an injunction, with the level of damages and scope of the injunction to be determined at trial, which occurred between October 24 and November 1, 2022. While the Court reserved judgment at the conclusion of the trial, the summary judgment decision and subsequent pre-trial decisions provide that the Court will assess trespass damages calculated using a pro-rata share of Enbridge's profits from the operation of the pipeline attributable to the 12 disputed parcels compared to the pipeline as a whole rather than the profits associated with the entire length of the pipeline, as the Band sought. The Court has also stated that any injunction will not result in the immediate closure of the pipeline but also will not allow the pipeline to operate indefinitely. On November 28, 2022, the Court issued an interim Order ruling that: (a) the parties are to meet and confer by December 16 on installation of EFRDs (Emergency Flow Restriction Devices) on the Reservation, an appropriate shutdown and purge protocol should conditions worsen at the meander, and any other reasonable remediation projects that could inhibit further erosion at the meander; (b) the parties are to submit a Joint Proposal by December 23 on appropriate shutoff and purge plan for the meander, or if they cannot agree, each party must submit their own best offer on a shutdown and purge protocol; and (c) denied Enbridge's request for declaratory and injunctive relief on its counterclaims asking for Court-Ordered relief relating to access and erosion mitigation at the meander. The parties met and conferred by December 16 and a Joint Status Report, along with individual best offers on shutdown and purge protocol, were filed on December 23. We continue to wait on the Court's rulings on the issues of financial compensation and Line 5's operations.

Michigan Line 5 Dual Pipelines - Straits of Mackinac Easement

In 2019, the Michigan Attorney General (AG) filed a complaint in the Michigan Ingham County Circuit Court (the Circuit Court) that requests the Circuit Court to declare the easement granted in 1953 that we have for the operation of Line 5 in the Straits of Mackinac (the Straits) to be invalid and to prohibit continued operation of Line 5 in the Straits. On December 15, 2021, we removed the case to the US District Court in the Western District of Michigan (US District Court), where it was assigned to Judge Janet T. Neff. The removal of the AG's case to federal court follows a November 16, 2021 ruling which held that the similar (and now dismissed) 2020 lawsuit brought by the Governor of Michigan to force Line 5's shutdown raised important federal issues that should be heard in federal court. On December 21, 2021, the AG made a request to file a remand motion and on December 28, 2021, we responded to her request to file that motion. On January 5, 2022, the court issued an Order allowing the AG to file a motion to remand the 2019 case. The AG's motion and brief were filed on January 14, 2022, and our response was filed on February 11, 2022. The motion was fully briefed in March 2022. On August 18, 2022, Judge Neff denied the AG's motion to remand which now remains in the US District Court. On August 30, 2022, the AG filed a motion to certify the US District Court's August 18 Order to pursue an appeal on the jurisdictional issue, which Enbridge opposed. We anticipate a decision on the jurisdictional issue in 2023.

Dakota Access Pipeline

We own an effective interest of 27.6% in the Bakken Pipeline System, which is inclusive of the Dakota Access Pipeline (DAPL). The Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed lawsuits in 2016 with the US Court for the District of Columbia (the District Court) contesting the lawfulness of the Army Corps easement for DAPL, including the adequacy of the Army Corps' environmental review and tribal consultation process. The Oglala Sioux and Yankton Sioux Tribes also filed lawsuits alleging similar claims in 2018.

On June 14, 2017, the District Court found the Army Corps' environmental review to be deficient and ordered the Army Corps to conduct further study concerning spill risks from DAPL. In August 2018, the Army Corps completed on remand the further environmental review ordered by the District Court and reaffirmed the issuance of the easement for DAPL. All four plaintiff Tribes subsequently amended their complaints to include claims challenging the adequacy of the Army Corps' August 2018 remand decision.

On March 25, 2020, in response to amended complaints from the Tribes, the District Court found the Army Corps' environmental review on remand was deficient and ordered the Army Corps to prepare an Environmental Impact Statement (EIS) to address unresolved controversy pertaining to potential spill impacts resulting from DAPL. On July 6, 2020, the District Court issued an order vacating the Army Corps' easement for DAPL and ordering that the pipeline be shut down by August 5, 2020. Dakota Access, LLC and the Army Corps appealed the decision and filed a motion for a stay pending appeal with the US Court of Appeals for the District of Columbia Circuit. On August 5, 2020, the US Court of Appeals stayed the District Court's July 6 order to shut down and empty the pipeline, but did not stay the District Court's March 25 order requiring the Army Corps to prepare an EIS or the District Court's July 6 order vacating the DAPL easement.

On January 26, 2021, the US Court of Appeals affirmed the District Court's decision, holding that the Army Corps is required to prepare an EIS and that the Army Corps' easement for DAPL is vacated. On February 22, 2022, the US Supreme Court denied the request of Dakota Access, LLC to review the decision that an EIS is required. The US Court of Appeals also determined that, absent considering the closure of DAPL in the context of an injunction proceeding, the District Court could not order DAPL's operations to cease. While not an issue before the US Court of Appeals, the US Court of Appeals also recognized that the Army Corps could consider whether to allow DAPL to continue to operate in the absence of an easement.

On May 21, 2021, the District Court dismissed the plaintiff Tribes' request for an injunction enjoining DAPL from operating until the Army Corps has completed its EIS. The right of the plaintiff Tribes to appeal the denial of the injunction request expired on July 20, 2021. The Army Corps earlier indicated that it did not intend, at that time, to exercise its authority to bar DAPL's continued operation, notwithstanding the absence of an easement and that it anticipates completion of the EIS process.

On July 22, 2021, the Army Corps filed a notice with the District Court advising that the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a notice asserting violations of federal safety regulations resulting from the operation of DAPL. The Army Corps stated that it would consider PHMSA's notice as part of its ongoing consideration of whether and how the Army Corps will enforce its rights on property crossed by the pipeline and in the context of the ongoing EIS. The Army Corps also granted the request from the Tribes to extend the draft EIS completion date to September 2022. The Army Corps now expects to complete the draft EIS in the spring of 2023.

OTHER LITIGATION
We and our subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS
We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

CRITICAL ACCOUNTING ESTIMATES

Our consolidated financial statements are prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP), which require management to make estimates, judgments and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. In making judgments and estimates, management relies on external information and observable conditions, where possible, supplemented by internal analysis as required. We believe our most critical accounting policies and estimates discussed below have an impact across the various segments of our business.

BUSINESS COMBINATIONS

We apply the provisions of Accounting Standards Codification (ASC) 805 *Business Combinations* in accounting for our acquisitions. The acquired long-lived assets, intangible assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition. Goodwill represents the excess of the purchase price over the fair value of net assets. While we use our best estimates and assumptions to accurately value assets acquired and liabilities assumed at the date of acquisition, as well as any contingent consideration, our estimates are inherently uncertain and subject to refinement. During the measurement period, which may be up to one year from the acquisition date, we record adjustments to the assets acquired and liabilities assumed with the corresponding offset to goodwill. Upon the conclusion of the measurement period or final determination of values of assets acquired or liabilities assumed, whichever comes first, any subsequent adjustments are recorded to our consolidated statements of operations.

Accounting for business combinations requires significant judgment, estimates and assumptions at the acquisition date. In developing estimates of fair values at the acquisition date, we utilize a variety of factors including market data, historical and future expected cash flows, growth rates and discount rates. The subjective nature of our assumptions increases the risk associated with estimates surrounding the projected performance of the acquired entity.

GOODWILL IMPAIRMENT

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. Our reporting units are Liquids Pipelines, Gas Transmission, Gas Distribution and Storage and Renewable Power Generation. The Renewable Power Generation reporting unit had goodwill starting in the third quarter of 2022.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends, changes to regulatory environments, capital accessibility, operating income trends and changes to industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. The fair value of our reporting units is estimated using a combination of discounted cash flow and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, expected future capital expenditures and working capital levels, as well as terminal value growth rates for the Liquids Pipelines, Gas Transmission and Renewable Power Generation reporting units, and projected regulatory rate base and rate base multiplier for the Gas Distribution and Storage reporting unit. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multiples for reporting units. The allocation of goodwill to held-for-sale and disposed businesses is based on the relative fair value of businesses included in the relevant reporting unit.

On April 1, 2022, we performed our annual goodwill impairment assessment which consisted of a qualitative assessment for the Liquids Pipelines, Gas Transmission and Gas Distribution and Storage reporting units and did not identify impairment indicators. Due to changes in the macroeconomic environment that has led to a rise in interest rates, we performed a quantitative assessment for the Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation reporting units as at December 1, 2022, which resulted in the recognition of an impairment loss in Gas Transmission. Goodwill impairments were not identified in relation to the Liquids Pipelines, Gas Distribution, or Renewable Power Generation reporting units.

ASSET IMPAIRMENT

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal or regulatory changes, or other factors indicate we may not recover the carrying amount of our assets. We regularly monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we will assess the fair value of the asset. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value.

With respect to equity method investments, we assess at each balance sheet date whether there is objective evidence that the investment is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is objective evidence of impairment, we determine whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the investment.

Asset fair value is determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the asset and the recognition of an impairment loss in the Consolidated Statements of Earnings.

ASSETS HELD FOR SALE

We classify assets as held for sale when management commits to a formal plan to actively market an asset or a group of assets and when management believes it is probable the sale of the assets will occur within one year. We measure assets classified as held for sale at the lower of their carrying value and their estimated fair value less costs to sell.

REGULATORY ACCOUNTING

Certain of our businesses are subject to regulation by various authorities, including but not limited to, the CER, the FERC, the Alberta Energy Regulator, La Régie de l'energie du Québec and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities. Key determinants in the ratemaking process are:

- costs of providing service, including operating costs, capital invested, depreciation expense and taxes;
- allowed rate of return, including the equity component of the capital structure and related income taxes;
- interest costs on the debt component of the capital structure; and
- contract and volume throughput assumptions.

The allowed rate of return is determined in accordance with the applicable regulatory model and may impact our profitability. The rates for a number of our projects are based on a cost-of-service recovery model that follows the regulators' authoritative guidance. Under the cost-of-service tolling methodology, we calculate tolls based on forecast volumes and cost. A difference between forecast and actual results causes an over or under recovery in any given year. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or expected to be paid to cover future abandonment costs in relation to the CER's Land Matters Consultation Initiative (LMCI) and for future removal and site restoration costs as approved by the OEB.

To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates.

As at December 31, 2022 and 2021, our regulatory assets totaled $6.5 billion and $5.9 billion, respectively, and regulatory liabilities totaled $3.8 billion and $3.4 billion, respectively.

DEPRECIATION

Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2022 and 2021, of $104.5 billion and $100.1 billion, respectively, is charged in accordance with two primary methods. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of our assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by our pipelines as well as the demand for crude oil and natural gas and the integrity of our systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of our business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

PENSION AND OTHER POSTRETIREMENT BENEFITS

We use certain assumptions relating to the calculation of defined benefit pension and other postretirement liabilities and net periodic benefit costs. These assumptions comprise management's best estimates of expected return on plan assets, future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments anticipated to be made under each of the respective plans. The expected return on plan assets is determined using market-related values and assumptions on the asset mix consistent with the investment policy relating to the assets and their projected returns. The assumptions are reviewed annually by our independent actuaries. Actual results that differ from results based on assumptions are amortized over future periods and, therefore, could materially affect the expense recognized and the recorded obligation in future periods.

The following sensitivity analysis identifies the impact on the December 31, 2022 Consolidated Financial Statements of a 0.5% change in key pension and other postretirement benefit (OPEB) obligation assumptions:

	Canada		United States	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Pension				
Decrease in discount rate	243	27	49	3
Decrease in expected return on assets	—	23	—	6
Decrease in rate of salary increase	(47)	(11)	(5)	(1)
OPEB				
Decrease in discount rate	13	1	5	—
Decrease in expected return on assets	N/A	N/A	—	1

CONTINGENT LIABILITIES

Provisions for claims filed against us are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on our financial results and certain subsidiaries and investments are detailed in Part II. *Item 8. Financial Statements and Supplementary Data - Note 31. Commitments and Contingencies*. In addition, any unasserted claims that later may become evident could have a material impact on our financial results and certain subsidiaries and investments.

ASSET RETIREMENT OBLIGATIONS
Asset retirement obligations (ARO) associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. The discount rates used to estimate the present value of the expected future cash flows for the year ended December 31, 2022 ranged from 1.5% to 9.0% (2021 - 0.9% to 9.0%). ARO is added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

In 2009, the CER issued a decision related to the LMCI, which required holders of an authorization to operate a pipeline under the CER Act to file a proposed process and mechanism to set aside funds to pay for future abandonment costs in respect of the sites in Canada used for the operation of a pipeline. The CER's decision stated that while pipeline companies are ultimately responsible for the full costs of abandoning pipelines, abandonment costs are a legitimate cost of providing service and are recoverable from the users of the pipeline upon approval by the CER. Following the CER's final approval of the collection mechanism and the set-aside mechanism for LMCI, we began collecting and setting aside funds to cover future abandonment costs effective January 1, 2015. The funds collected are held in trust in accordance with the CER decision. The funds collected from shippers are reported within Transportation and other services revenues and Restricted long-term investments. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense and Other long-term liabilities.

CHANGES IN ACCOUNTING POLICIES

Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 3. Changes in Accounting Policies*.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk
We generate certain revenues, incur expenses and hold a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

We employ financial derivative instruments to hedge foreign currency denominated earnings exposure. A combination of qualifying cash flow, fair value and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses and to manage variability in cash flows. We hedge certain net investments in US dollar-denominated investments and subsidiaries using foreign currency derivatives and US dollar-denominated debt.

Interest Rate Risk
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% of floating rate debt as a percentage of total debt outstanding. We primarily use qualifying derivative instruments to manage interest rate risk. Pay fixed-receive floating interest rate swaps may be used to hedge against the effect of future interest rate movements. We have implemented a hedging program to partially mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps. These hedges have an average fixed rate of 4.0%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of changes in market interest rates. Pay floating-receive fixed interest rate swaps are used, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in fair value via execution of fixed to floating interest rate swaps. As at December 31, 2022, we do not have any pay floating-receive fixed interest rate swaps outstanding.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have established a program including some of our subsidiaries to partially mitigate our exposure to long-term interest rate variability on forecasted term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.2%.

Commodity Price Risk
Our earnings and cash flows are exposed to changes in commodity prices as a result of our ownership interests in certain assets and investments, as well as through the activities of our energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. We employ financial and physical derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use primarily non-qualifying derivative instruments to manage commodity price risk.

Equity Price Risk
Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. We use equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted share units. We use a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

Market Risk Management
We have a Risk Policy to minimize the likelihood that adverse cash flow impacts arising from movements in market prices will exceed a defined risk tolerance. We identify and measure all material market risks including commodity price risks, interest rate risks, foreign exchange risk and equity price risk using a standardized measurement methodology. Our market risk metric consolidates the exposure after accounting for the impact of offsetting risks and limits the consolidated cash flow volatility arising from market related risks to an acceptable approved risk tolerance threshold. Our market risk metric is Cash Flow at Risk (CFaR).

CFaR is a statistically derived measurement used to measure the maximum cash flow loss that could potentially result from adverse market price movements over a one month holding period for price sensitive non-derivative exposures and for derivative instruments we hold or issue as recorded in the Consolidated Statements of Financial Position as at December 31, 2022. CFaR assumes that no further mitigating actions are taken to hedge or otherwise minimize exposures and the selection of a one month holding period reflects the mix of price risk sensitive assets at Enbridge. As a practical matter, a large portion of Enbridge's exposure could be hedged or unwound in a much shorter period if required to mitigate the risks.

The consolidated CFaR policy limit for Enbridge is 3.5% of its forward 12 month normalized cash flow. At December 31, 2022 and 2021 CFaR was $144 million and $103 million or 1.3% and 0.9%, respectively, of estimated 12 month forward normalized cash flow.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. Our shelf prospectuses with securities regulators enable ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2022. As a result, all credit facilities are available to us and the banks are obligated to fund us under the terms of the facilities.

CREDIT RISK

Entering into derivative instruments may result in exposure to credit risk from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, we enter into risk management transactions primarily with institutions that possess strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through maintenance and monitoring of credit exposure limits and contractual requirements, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our financial derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit events and reduce our credit risk exposure on financial derivative asset positions outstanding with the counterparties in those circumstances.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimates of market value based on generally accepted valuation techniques or models and is supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enbridge Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated statements of financial position of Enbridge Inc. and its subsidiaries (together, the Company) as of December 31, 2022 and 2021, and the related consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2022, including the related notes (collectively referred to as the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Goodwill Impairment Assessment

As described in Notes 2 and 16 to the consolidated financial statements, the Company's goodwill balance was $32,440 million at December 31, 2022. As disclosed by management, an annual goodwill impairment assessment is performed at the reporting unit level as of April 1 of each year, or more frequently if events or circumstances indicate that the carrying value of goodwill may be impaired. Management has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. In making the qualitative assessment, management considers macroeconomic trends, changes to regulatory environments, capital accessibility, operating income trends and changes to industry conditions. The quantitative goodwill impairment assessment involves determining the fair value of the Company's reporting units and comparing those values to the carrying value of each reporting unit, including goodwill. Fair value is estimated using a combination of discounted cash flow and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, expected future capital expenditures and working capital levels, as well as terminal value growth rates for the Liquids Pipelines, Gas Transmission and Midstream (Gas Transmission) and Renewable Power Generation reporting units and projected regulatory rate base and rate base multiple for the Gas Distribution and Storage (Gas Distribution) reporting unit. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multiples. Management elected to perform a qualitative goodwill impairment assessment as of April 1, 2022 for the following reporting units: Liquids Pipelines, Gas Transmission and Gas Distribution and did not identify impairment indicators. Due to changes in the macroeconomic environment that led to a rise in interest rates, management performed a quantitative assessment as of December 1, 2022 for the following reporting units: Liquids Pipelines, Gas Transmission, Gas Distribution and Renewable Power Generation. A goodwill impairment of $2,465 million was recorded in relation to the Gas Transmission reporting unit. Goodwill impairments were not identified in relation to the Liquids Pipelines, Gas Distribution or Renewable Power Generation reporting units.

The principal considerations for our determination that performing procedures relating to the goodwill impairment assessment is a critical audit matter are the significant judgments required by management when developing such significant assumptions as discount rates, projected operating income, expected future capital expenditures, terminal value growth rates, projected regulatory rate base, rate base multiple and earnings multiples used to estimate the fair value of the reporting units, as applicable, as of December 1, 2022. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures to evaluate the reasonableness of management’s significant assumptions used in the quantitative assessment. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s quantitative goodwill impairment assessment, including controls over the determination of the fair value estimates of the Company’s reporting units. These procedures also included, among others, testing management’s process for developing the fair value estimates of the Company’s reporting units. Testing management’s process for developing the fair value estimates included evaluating the appropriateness of the discounted cash flow and the earnings multiples models; testing the completeness and accuracy of underlying data used in the models; and evaluating the reasonableness of significant assumptions used by management in determining the fair value estimates including discount rates, projected operating income, expected future capital expenditures, projected regulatory rate base and rate base multiple, terminal value growth rates and earnings multiples. Assessing the reasonableness of projected operating income, expected future capital expenditures and the projected regulatory rate base involved evaluating whether these significant assumptions were reasonable considering the current and past performance of the Company’s reporting units, external industry data and evidence obtained in other areas of the audit, as applicable. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of management’s discounted cash flow and earnings multiples models and evaluating the reasonableness of significant assumptions used in the models, specifically discount rates, terminal value growth rates, rate base multiple and earnings multiples.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 10, 2023

We have served as the Company's auditor since 1949.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars, except per share amounts)			
Operating revenues			
Commodity sales	**29,150**	26,873	19,259
Gas distribution sales	**5,653**	4,026	3,663
Transportation and other services	**18,506**	16,172	16,165
Total operating revenues *(Note 4)*	**53,309**	47,071	39,087
Operating expenses			
Commodity costs	**28,942**	26,608	18,890
Gas distribution costs	**3,647**	2,094	1,779
Operating and administrative	**8,219**	6,712	6,749
Depreciation and amortization	**4,317**	3,852	3,712
Impairment of long-lived assets	**541**	—	—
Impairment of goodwill *(Note 16)*	**2,465**	—	—
Total operating expenses	**48,131**	39,266	31,130
Operating income	**5,178**	7,805	7,957
Income from equity investments *(Note 13)*	**2,056**	1,711	1,136
Impairment of equity investments *(Note 13)*	**—**	(111)	(2,351)
Gain on joint venture merger transaction *(Note 13)*	**1,076**	—	—
Other income/(expense) *(Note 28)*	**(589)**	979	238
Interest expense *(Note 18)*	**(3,179)**	(2,655)	(2,790)
Earnings before income taxes	**4,542**	7,729	4,190
Income tax expense *(Note 25)*	**(1,604)**	(1,415)	(774)
Earnings	**2,938**	6,314	3,416
(Earnings)/loss attributable to noncontrolling interests	**65**	(125)	(53)
Earnings attributable to controlling interests	**3,003**	6,189	3,363
Preference share dividends	**(414)**	(373)	(380)
Earnings attributable to common shareholders	**2,589**	5,816	2,983
Earnings per common share attributable to common shareholders *(Note 6)*	**1.28**	2.87	1.48
Diluted earnings per common share attributable to common shareholders *(Note 6)*	**1.28**	2.87	1.48

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings	**2,938**	6,314	3,416
Other comprehensive income/(loss), net of tax			
Change in unrealized gain/(loss) on cash flow hedges	**847**	162	(457)
Change in unrealized gain/(loss) on net investment hedges	**(971)**	49	102
Other comprehensive loss from equity investees	**(6)**	(12)	(1)
Excluded components of fair value hedges	**(35)**	(5)	5
Reclassification to earnings of loss on cash flow hedges	**143**	235	198
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**(10)**	21	13
Reclassification to earnings of (gain)/loss on equity investees	**16**	(62)	—
Actuarial gain/(loss) on pension and OPEB	**312**	394	(167)
Foreign currency translation adjustments	**4,406**	(507)	(853)
Other comprehensive income/(loss), net of tax	**4,702**	275	(1,160)
Comprehensive income	**7,640**	6,589	2,256
Comprehensive income attributable to noncontrolling interests	**(21)**	(95)	(22)
Comprehensive income attributable to controlling interests	**7,619**	6,494	2,234
Preference share dividends	**(414)**	(373)	(380)
Comprehensive income attributable to common shareholders	**7,205**	6,121	1,854

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	2022	2021	2020
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 21)*			
Balance at beginning of year	**7,747**	7,747	7,747
Redemption of preference shares	**(929)**	—	—
Balance at end of year	**6,818**	7,747	7,747
Common shares *(Note 21)*			
Balance at beginning of year	**64,799**	64,768	64,746
Shares issued on exercise of stock options	**53**	31	22
Share purchases at stated value	**(88)**	—	—
Other	**(4)**	—	—
Balance at end of year	**64,760**	64,799	64,768
Additional paid-in capital			
Balance at beginning of year	**365**	277	187
Stock-based compensation	**36**	28	30
Purchase of noncontrolling interest	**(43)**	—	—
Options exercised	**(50)**	(23)	(21)
Change in reciprocal interest	**—**	98	76
Other	**(33)**	(15)	5
Balance at end of year	**275**	365	277
Deficit			
Balance at beginning of year	**(10,989)**	(9,995)	(6,314)
Earnings attributable to controlling interests	**3,003**	6,189	3,363
Preference share dividends	**(414)**	(373)	(380)
Common share dividends declared	**(7,023)**	(6,818)	(6,612)
Dividends paid to reciprocal shareholder	**—**	8	17
Modified retrospective adoption of *ASU 2016-13 Financial Instruments - Credit Losses*	**—**	—	(66)
Share purchases in excess of stated value	**(63)**	—	—
Other	**—**	—	(3)
Balance at end of year	**(15,486)**	(10,989)	(9,995)
Accumulated other comprehensive income/(loss) *(Note 23)*			
Balance at beginning of year	**(1,096)**	(1,401)	(272)
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**4,616**	305	(1,129)
Balance at end of year	**3,520**	(1,096)	(1,401)
Reciprocal shareholding			
Balance at beginning of year	**—**	(29)	(51)
Change in reciprocal interest	**—**	29	22
Balance at end of year	**—**	—	(29)
Total Enbridge Inc. shareholders' equity	**59,887**	60,826	61,367
Noncontrolling interests *(Note 20)*			
Balance at beginning of year	**2,542**	2,996	3,364
Earnings/(loss) attributable to noncontrolling interests	**(65)**	125	53
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized loss on cash flow hedges	**(28)**	(15)	(6)
Foreign currency translation adjustments	**114**	(15)	(25)
	86	(30)	(31)
Comprehensive income attributable to noncontrolling interests	**21**	95	22
Distributions	**(259)**	(271)	(300)
Contributions	**1,105**	15	23
Redemption of noncontrolling interests	**—**	(293)	(112)
Purchase of noncontrolling interest	**55**	—	—
Other	**47**	—	(1)
Balance at end of year	**3,511**	2,542	2,996
Total equity	**63,398**	63,368	64,363
Dividends paid per common share	**3.44**	3.34	3.24

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating activities			
Earnings	**2,938**	6,314	3,416
Adjustments to reconcile earnings to net cash provided by operating activities:			
Depreciation and amortization	**4,317**	3,852	3,712
Deferred income tax expense *(Note 25)*	**957**	1,091	447
Unrealized derivative fair value (gain)/loss, net *(Note 24)*	**1,280**	(173)	(756)
Income from equity investments *(Note 13)*	**(2,056)**	(1,711)	(1,136)
Distributions from equity investments	**1,827**	1,630	1,392
Impairment of long-lived assets	**541**	—	—
Impairment of equity investments *(Note 13)*	**—**	111	2,351
Impairment of goodwill *(Note 16)*	**2,465**	—	—
Gain on joint venture merger transaction *(Note 13)*	**(1,076)**	—	—
(Gain)/loss on dispositions	**12**	(319)	(6)
Other	**37**	(73)	268
Changes in operating assets and liabilities *(Note 29)*	**(12)**	(1,466)	93
Net cash provided by operating activities	**11,230**	9,256	9,781
Investing activities			
Capital expenditures	**(4,647)**	(7,818)	(5,405)
Long-term investments and restricted long-term investments	**(1,041)**	(640)	(487)
Distributions from equity investments in excess of cumulative earnings	**763**	533	705
Additions to intangible assets	**(174)**	(275)	(215)
Acquisitions	**(828)**	(3,785)	(24)
Proceeds from joint venture merger transaction *(Note 13)*	**522**	—	—
Proceeds from dispositions	**—**	1,263	265
Affiliate loans, net	**135**	65	(16)
Net cash used in investing activities	**(5,270)**	(10,657)	(5,177)
Financing activities			
Net change in short-term borrowings	**481**	394	223
Net change in commercial paper and credit facility draws	**(1,333)**	2,960	1,542
Debenture and term note issues, net of issue costs	**7,547**	8,032	5,230
Debenture and term note repayments	**(4,198)**	(2,264)	(4,463)
Sale of noncontrolling interest in subsidiary *(Note 8)*	**1,092**	—	—
Contributions from noncontrolling interests	**13**	15	23
Distributions to noncontrolling interests	**(259)**	(271)	(300)
Common shares issued	**3**	5	5
Common shares repurchased	**(151)**	—	—
Preference share dividends	**(338)**	(367)	(380)
Common share dividends	**(6,968)**	(6,766)	(6,560)
Redemption of preference shares	**(1,003)**	—	—
Redemption of preferred shares held by subsidiary	**—**	(415)	—
Other	**(314)**	(87)	(90)
Net cash provided by/(used in) financing activities	**(5,428)**	1,236	(4,770)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**55**	(5)	(20)
Net change in cash and cash equivalents and restricted cash	**587**	(170)	(186)
Cash and cash equivalents and restricted cash at beginning of year	**320**	490	676
Cash and cash equivalents and restricted cash at end of year	**907**	320	490
Supplementary cash flow information			
Cash paid for income taxes	**495**	489	524
Cash paid for interest, net of amount capitalized	**2,920**	2,427	2,538
Property, plant and equipment and intangible assets non-cash accruals	**937**	831	801

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2022**	2021
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**861**	286
Restricted cash	**46**	34
Accounts receivable and other *(Note 9)*	**8,871**	6,862
Accounts receivable from affiliates	**114**	107
Inventory *(Note 10)*	**2,255**	1,670
	12,147	8,959
Property, plant and equipment, net *(Note 11)*	**104,460**	100,067
Long-term investments *(Note 13)*	**15,936**	13,324
Restricted long-term investments *(Note 14)*	**593**	630
Deferred amounts and other assets	**9,542**	8,613
Intangible assets, net *(Note 15)*	**4,018**	4,008
Goodwill *(Note 16)*	**32,440**	32,775
Deferred income taxes *(Note 25)*	**472**	488
Total assets	**179,608**	168,864
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 18)*	**1,996**	1,515
Accounts payable and other *(Note 17)*	**11,392**	9,767
Accounts payable to affiliates	**105**	90
Interest payable	**763**	693
Current portion of long-term debt *(Note 18)*	**6,045**	6,164
	20,301	18,229
Long-term debt *(Note 18)*	**72,939**	67,961
Other long-term liabilities	**9,189**	7,617
Deferred income taxes *(Note 25)*	**13,781**	11,689
	116,210	105,496
Commitments and contingencies *(Note 31)*		
Equity		
Share capital *(Note 21)*		
Preference shares	**6,818**	7,747
Common shares *(2,025 and 2,026 outstanding at December 31, 2022 and 2021, respectively)*	**64,760**	64,799
Additional paid-in capital	**275**	365
Deficit	**(15,486)**	(10,989)
Accumulated other comprehensive income/(loss) *(Note 23)*	**3,520**	(1,096)
Total Enbridge Inc. shareholders' equity	**59,887**	60,826
Noncontrolling interests *(Note 20)*	**3,511**	2,542
	63,398	63,368
Total liabilities and equity	**179,608**	168,864

Variable Interest Entities (VIEs) *(Note 12)*
The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
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1. BUSINESS OVERVIEW

The terms "we", "our", "us" and "Enbridge" as used in this report refer collectively to Enbridge Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge.

Enbridge is a publicly traded energy transportation and distribution company. We conduct our business through five business segments: Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation, and Energy Services. These reporting segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES
Liquids Pipelines consists of pipelines and terminals in Canada and the United States (US) that transport and export various grades of crude oil and other liquid hydrocarbons, including the Mainline System, Regional Oil Sands System, Gulf Coast and Mid-Continent, and Other. This segment also includes Moda Midstream Operating, LLC (Moda), which was acquired on October 12, 2021 *(Note 8)* and is a component of Gulf Coast and Mid-Continent.

GAS TRANSMISSION AND MIDSTREAM
Gas Transmission and Midstream consists of our investments in natural gas pipelines and gathering and processing facilities in Canada and the US, including US Gas Transmission, Canadian Gas Transmission, US Midstream, and Other.

GAS DISTRIBUTION AND STORAGE
Gas Distribution and Storage consists of our natural gas utility operations, the core of which is Enbridge Gas Inc. (Enbridge Gas), which serves residential, commercial and industrial customers throughout Ontario. This business segment also includes natural gas distribution activities in Québec. We sold our investment in Noverco Inc. (Noverco), previously reported in the Gas Distribution and Storage segment, to Trencap L.P. on December 30, 2021 *(Note 13)*.

RENEWABLE POWER GENERATION
Renewable Power Generation consists primarily of investments in wind and solar assets, as well as geothermal, waste heat recovery, and transmission assets. In North America, assets are primarily located in the provinces of Alberta, Saskatchewan, Ontario and Québec, and in the states of Colorado, Texas, Indiana and West Virginia. We also have offshore wind assets in operation and under development in the United Kingdom, Germany and France. This segment also includes Tri Global Energy, LLC (TGE) which was acquired on September 27, 2022 *(Note 8).*

ENERGY SERVICES
Our Energy Services businesses in Canada and the US undertake physical commodity marketing activity and logistical services to manage our volume commitments on various pipeline systems. Energy Services also provides energy marketing services to North American refiners, producers and other customers.

ELIMINATIONS AND OTHER
In addition to the segments described above, Eliminations and Other includes operating and administrative costs that are not allocated to business segments, the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiaries. The principal activity of our captive insurance subsidiaries is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. Eliminations and Other also includes new business development activities and corporate investments.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (US GAAP). Amounts are stated in Canadian dollars unless otherwise noted. As a Securities and Exchange Commission (SEC) registrant, we are permitted to use US GAAP for the purposes of meeting both our Canadian and US continuous disclosure requirements.

BASIS OF PRESENTATION AND USE OF ESTIMATES
The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: variable consideration included in revenue *(Note 4);* carrying values of regulatory assets and liabilities *(Note 7)*; purchase price allocations *(Note 8)*; unbilled revenues; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 11)*; amortization rates and carrying value of intangible assets *(Note 15)*; measurement of goodwill *(Note 16)*; fair value of asset retirement obligations (ARO) *(Note 19)*; valuation of stock-based compensation *(Note 22)*; fair value of financial instruments *(Note 24)*; provisions for income taxes *(Note 25)*; assumptions used to measure retirement benefits and OPEB *(Note 26)*; commitments and contingencies *(Note 31)*; and estimates of losses related to environmental remediation obligations *(Note 31)*. Actual results could differ from these estimates.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

PRINCIPLES OF CONSOLIDATION
The consolidated financial statements include our accounts and the accounts of our subsidiaries and VIEs for which we are the primary beneficiary. A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains and losses of the entity. Upon inception of a contractual agreement, we perform an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a VIE. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses, or the right to receive benefits from, the VIE that could potentially be significant to the VIE. Where we conclude that we are the primary beneficiary of a VIE, we consolidate the accounts of that VIE. We assess all variable interests in the entity and use our judgment when determining if we are the primary beneficiary. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. We assess the primary beneficiary determination for a VIE on an ongoing basis if there are changes in the facts and circumstances related to a VIE. If an entity is determined to not be a VIE, the voting interest entity model is applied, where an investor holding the majority voting rights consolidates the entity. The consolidated financial statements also include the accounts of any limited partnerships where we represent the general partner and, based on all facts and circumstances, control such limited partnerships, unless the limited partner has substantive participating rights or substantive kick-out rights. For certain investments where we retain an undivided interest in assets and liabilities, we record our proportionate share of assets, liabilities, revenues and expenses.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests. Investments and entities over which we exercise significant influence are accounted for using the equity method.

REGULATION

Certain parts of our businesses are subject to regulation by various authorities including, but not limited to, the Canada Energy Regulator (CER), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the Ontario Energy Board (OEB) and la Régie de l'energie du Québec. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or to be paid to cover future abandonment costs in relation to the CER's Land Matters Consultation Initiative (LMCI). Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates. We believe that the recovery of our regulatory assets as at December 31, 2022 is probable over the periods described in *Note 7 - Regulatory Matters*.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component, which are both capitalized based on rates set out in a regulatory agreement. The corresponding impact on earnings is included in Interest expense for the interest component and Other income/(expense) for the equity component. In the absence of rate regulation, we would capitalize interest using a capitalization rate based on our cost of borrowing, whereas the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation relating to the equity component would not be recognized. The equity component of AFUDC is included as a non-cash reconciling item to earnings within Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows.

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains and losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

With the approval of regulators, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

For certain regulated operations to which US GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with US GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with US GAAP and no regulatory asset is recorded.

REVENUE RECOGNITION

For businesses that are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer creditworthiness is assessed prior to agreement signing, as well as throughout the contract duration. Certain revenues from our liquids and natural gas pipeline businesses are recognized under the terms of committed delivery contracts, rather than the cash tolls received.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts ratably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry. We recognize revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires or when it is determined that the likelihood that the shipper will utilize the make-up right is remote. We also have long-term contracts where the revenue profile does not align with the cash receipt schedule, resulting in the recognition of deferred revenue.

Certain offshore pipeline transportation contracts require us to provide transportation services for the life of the underlying producing fields. Under these arrangements, shippers pay us a fixed monthly toll for a defined period of time which may be shorter than the estimated reserve life of the underlying producing fields, resulting in a contract period which extends past the period of cash collection. Fixed monthly toll revenues are recognized ratably over the committed volume made available to shippers throughout the contract period, regardless of when cash is received.

For the years ended December 31, 2022, 2021 and 2020, cash received net of revenue recognized for contracts under make-up rights and similar deferred revenue arrangements was $238 million, $127 million and $292 million, respectively.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. Natural gas utility revenues are recorded based on regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas.

Our Energy Services segment enters into commodity purchase and sale arrangements that are recorded on a gross basis as the related contracts are not held for trading purposes and we are acting as the principal in the transactions.

No non-affiliated customer exceeded 10.0% of our third-party revenues for the year ended December 31, 2022. Our largest non-affiliated customer accounted for approximately 13.5% and 13.6% of our third-party revenues for the years ended December 31, 2021 and 2020, respectively.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Commodity sales, Transportation and other services revenue, Commodity costs, Operating and administrative expense, Other income/(expense) and Interest expense.

Derivatives in Qualifying Hedging Relationships
We use derivative financial instruments to manage our exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to our share price. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges.

Cash Flow Hedges
We use cash flow hedges to manage our exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to our share price. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Fair Value Hedges
We may use fair value hedges to hedge the fair value of debt instruments. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged risk of the asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged risk of the asset or liability ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges
Gains and losses arising from the translation of our net investment in foreign operations from their functional currencies to Enbridge's Canadian dollar presentation currency are included in cumulative translation adjustments (CTA), a component of OCI. We currently have designated a portion of our US dollar-denominated debt, as well as a portfolio of foreign exchange forward contracts in prior periods, as a hedge of our net investment in US dollar-denominated investments and subsidiaries. As a result, the change in fair value of the foreign currency derivatives, as well as the translation of US dollar-denominated debt, are reflected in OCI. Amounts recognized previously in Accumulated other comprehensive income/(loss) (AOCI) are reclassified to earnings when there is a reduction of the hedged net investment resulting from the disposal of a foreign operation.

Classification of Derivatives
We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

Transaction Costs
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a reduction to Long-term debt in the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

EQUITY INVESTMENTS
Equity investments over which we exercise significant influence, but do not have controlling financial interests, are accounted for using the equity method. These investments are initially measured at cost and are adjusted for our proportionate share of undistributed equity earnings or loss. Our equity investments are increased for contributions made to, and decreased for distributions received from, the investee. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, we capitalize interest costs associated with the investment during such period.

RESTRICTED LONG-TERM INVESTMENTS
Long-term investments that are restricted as to withdrawal or usage for the purposes of the CER's LMCI are presented as Restricted long-term investments in the Consolidated Statements of Financial Position.

OTHER INVESTMENTS
Generally, we classify equity investments in entities over which we do not exercise significant influence and that do not have readily determinable fair values as other investments measured using the fair value measurement alternative (FVMA). These investments are recorded at cost less impairment, if any, and adjusted for the impact of observable price changes occurring in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the FVMA are reviewed for impairment each reporting period and written down to their fair value if objective evidence of impairment is identified. Equity investments with readily determinable fair values are measured at fair value through earnings. Dividends received from investments in equity securities are recognized in earnings when the right to receive payment is established.

Investments in debt securities are classified as available-for-sale and measured at fair value through OCI.

NONCONTROLLING INTERESTS
Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries. The portion of equity not owned by us in such entities is reflected as Noncontrolling interests within the equity section of the Consolidated Statements of Financial Position.

INCOME TAXES
Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent that taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated to the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting from the translation of monetary assets and liabilities are included in earnings in the period in which they arise.

Gains and losses arising from the translation of foreign operations' functional currencies to our Canadian dollar presentation currency are included in the CTA component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect as at the balance sheet date, while revenues and expenses are translated using monthly average exchange rates.

CASH AND CASH EQUIVALENTS
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

RESTRICTED CASH
Cash and cash equivalents that are restricted as to withdrawal or usage for the purposes of the CER's LMCI or in accordance with specific commercial arrangements are presented as Restricted cash in the Consolidated Statements of Financial Position.

LOANS AND RECEIVABLES
Long-term notes receivable from affiliates are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Accounts receivable and other are measured at cost. Interest income is recognized in earnings as it is earned with the passage of time.

CURRENT EXPECTED CREDIT LOSSES
For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations. Other loan receivables and applicable off-balance sheet commitments utilize a discounted cash flow methodology which calculates the current expected credit losses based on historical default probability rates associated with the credit rating of the counterparty and the related term of the loan or commitment, adjusted for forward-looking information and management expectations.

NATURAL GAS IMBALANCES
The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received from, and delivered for, customers. As settlement of certain imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. Most natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

INVENTORY
Inventory is comprised of natural gas held in storage by Enbridge Gas, crude oil and natural gas held primarily by businesses in the Energy Services segment and materials and supplies. Natural gas held in storage by Enbridge Gas is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of gas purchased is deferred as a liability for future refund, or as an asset for collection, as approved by the OEB. Other inventory is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, other commodities inventory is recorded to Commodity costs in the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value. Materials and supplies inventory is recorded at the lower of average cost or net realizable value.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. We capitalize interest incurred during construction for non-rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset.

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting for property, plant and equipment is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are generally not reflected in earnings but are booked as an adjustment to accumulated depreciation.

LEASES

We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach applied for other long-lived assets.

Lease liabilities and ROU assets require the use of judgment and estimates which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily consists of costs that regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; the fair value adjustment to long-term debt; actual cost of removal of previously retired or decommissioned plant assets; the difference between the actual cost and approved cost of natural gas reflected in rates; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs, customer relationships and emission allowances. We capitalize costs incurred during the application development stage of internal use software projects. Customer relationships represent the underlying relationship from long-term agreements with customers that are capitalized upon acquisition. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use, with the exception of emission allowances, which are not amortized as they will be used to satisfy compliance obligations as they come due.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components, and whether the economic and regulatory characteristics are similar. Our reporting units are Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation. The Renewable Power Generation reporting unit had goodwill beginning in the third quarter of 2022.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends, changes to regulatory environments, capital accessibility, operating income trends and changes to industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit’s carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. The fair value of our reporting units is estimated using a combination of discounted cash flow and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, expected future capital expenditures and working capital levels, as well as terminal value growth rates for the Liquids Pipelines, Gas Transmission and Renewable Power Generation reporting units, and projected regulatory rate base and rate base multiple for the Gas Distribution and Storage reporting unit. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multiples for reporting units.

The allocation of goodwill to held-for-sale and disposed businesses is based on the relative fair value of businesses included in the relevant reporting unit.

On April 1, 2022, we performed our annual goodwill impairment assessment which consisted of a qualitative assessment for the Liquids Pipelines, Gas Transmission and Gas Distribution and Storage reporting units and did not identify impairment indicators. Due to changes in the macroeconomic environment that have led to a rise in interest rates, we performed a quantitative assessment for the Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation reporting units as at December 1, 2022, which resulted in the recognition of an impairment loss for Gas Transmission *(Note 16)*. Goodwill impairments were not identified in relation to the Liquids Pipelines, Gas Distribution and Storage or Renewable Power Generation reporting units. Also, we did not identify any indicators of goodwill impairment during the remainder of 2022.

IMPAIRMENT

We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds its expected undiscounted cash flows, we will calculate fair value based on the discounted cash flows and write the asset down to the extent that the carrying value exceeds the fair value.

With respect to investments in debt securities and equity investments, we assess at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is objective evidence of impairment, we value the expected discounted cash flows using observable market inputs. We determine whether the decline below carrying value is other-than-temporary for equity method investments or is due to a credit loss for investments in debt securities. If the decline is determined to be other-than-temporary for equity method investments or is due to a credit loss for investments in debt securities, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

ASSET RETIREMENT OBLIGATIONS
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. Fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

PENSION AND OTHER POSTRETIREMENT BENEFITS
We sponsor defined benefit and defined contribution pension plans, as well as defined benefit OPEB plans.

Obligations and net periodic benefit costs for defined benefit pension and OPEB plans are estimated using the projected unit credit method, which is based on years of service, as well as our best estimates of actuarial assumptions such as discount rates, future salary levels, other cost escalations, employees' retirement ages, and mortality.

We determine discount rates using market yields of high-quality corporate bonds with maturities that approximate the estimated timing of future benefit payments.

Plan assets are measured at fair value. The expected return on plan assets is determined using the long-term target asset mixes in our investment policies and long-term market expectations.

Actuarial gains and losses arise from the difference between the actual and expected return on plan assets, and changes in actuarial assumptions such as discount rates. Periodic net actuarial gains and losses and prior service costs are accumulated and presented as follows in the Consolidated Statements of Financial Position:

- as a component of AOCI, for our non-utilities' defined benefit pension plans and all defined benefit OPEB plans; and
- as a component of Deferred amounts and other assets and/or Other long-term liabilities, for our utilities' defined benefit pension plans, to the extent that the net actuarial gains and losses and prior service costs have been permitted or are expected to be permitted by the regulators, to be recovered through future rates.

Net periodic benefit cost is recognized in earnings and includes:

- current service cost;
- interest cost;
- expected return on plan assets;
- amortization of prior service costs over the expected average remaining service life of the plans' active employee group; and
- amortization of net actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the fair value of plan assets, over the expected average remaining service life of the plans' active employee group.

Our utility operations also record regulatory adjustments for the difference between net periodic benefit costs for accounting versus ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be recovered from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to earnings and OCI on an accrual basis.

For defined contribution plans, our contributions are expensed when the contribution occurs.

STOCK-BASED COMPENSATION

Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISO granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Additional paid-in capital. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest one-third annually from the grant date. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of Enbridge’s common shares with an offset to Accounts payable and other or Other long-term liabilities. The value of the PSUs is also dependent on our performance relative to performance targets set out under the plan. We also award share settled RSUs which vest at the completion of a three-year term. During the vesting term, compensation expense is recorded based on the number of units granted and the market price of Enbridge's common shares on the day immediately preceding the grant date, with an offset to Additional paid-in capital.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES
We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations, taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in Accounts payable and other and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in the Consolidated Statements of Financial Position.

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

CHANGES IN ACCOUNTING POLICIES
There were no changes in accounting policies during the year ended December 31, 2022.

ADOPTION OF NEW ACCOUNTING STANDARDS
Disclosures About Government Assistance
Effective January 1, 2022, we adopted Accounting Standards Update (ASU) 2021-10 on a prospective basis. The new standard was issued in November 2021 to increase the transparency of government assistance to business entities. The ASU adds new disclosure requirements for transactions with governments that are accounted for using a grant or contribution accounting model by analogy. The required disclosures include information about the nature of transactions, accounting policy applied, impacted financial statement line items and significant terms and conditions. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Certain Lessor Leases with Variable Lease Payments
Effective January 1, 2022, we adopted ASU 2021-05 on a prospective basis. The new standard was issued in July 2021 to amend lessor accounting for certain leases with variable lease payments that do not depend on a reference index or a rate and would have resulted in the recognition of a loss at lease commencement if classified as a sales-type or a direct financing lease. The ASU amends the classification requirements of such leases for lessors to result in an operating lease classification. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Modifications or Exchanges of Certain Equity-Classified Contracts
Effective January 1, 2022, we adopted ASU 2021-04 on a prospective basis. The new standard was issued in May 2021 to clarify issuer accounting for modifications or exchanges of freestanding equity-classified written call options that remain equity classified after modification or exchange. The ASU requires an issuer to determine the accounting for the modification or exchange based on the economic substance of the modification or exchange. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Convertible Instruments and Contracts in an Entity's Own Equity
Effective January 1, 2022, we adopted ASU 2020-06 on a modified retrospective basis. The new standard was issued in August 2020 to simplify accounting for certain financial instruments. The ASU eliminates the current models that require separation of beneficial conversion and cash conversion features from convertible instruments and simplifies the derivative scope exception guidance pertaining to equity classification of contracts in an entity's own equity. The ASU also introduces additional disclosures for convertible debt and freestanding instruments that are indexed to and settled in an entity's own equity. The ASU amends the diluted earnings per share guidance, including the requirement to use if-converted method for all convertible instruments and an update for instruments that can be settled in either cash or shares. The adoption of this ASU did not have a material impact on our consolidated financial statements.

4. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Products and Services

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	**11,283**	**5,012**	**782**	**—**	**—**	**—**	**17,077**
Storage and other revenue	**235**	**350**	**308**	**—**	**—**	**—**	**893**
Gas gathering and processing revenue	**—**	**22**	**—**	**—**	**—**	**—**	**22**
Gas distribution revenue	**—**	**—**	**5,643**	**—**	**—**	**—**	**5,643**
Electricity and transmission revenue	**—**	**—**	**—**	**281**	**—**	**—**	**281**
Total revenue from contracts with customers	**11,518**	**5,384**	**6,733**	**281**	**—**	**—**	**23,916**
Commodity sales	**—**	**—**	**—**	**—**	**29,150**	**—**	**29,150**
Other revenue[1,2]	**(81)**	**39**	**(20)**	**305**	**—**	**—**	**243**
Intersegment revenue	**615**	**3**	**16**	**(4)**	**25**	**(655)**	**—**
Total revenue	**12,052**	**5,426**	**6,729**	**582**	**29,175**	**(655)**	**53,309**

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	9,492	4,364	676	—	—	—	14,532
Storage and other revenue	147	255	246	—	—	—	648
Gas gathering and processing revenue	—	49	—	—	—	—	49
Gas distribution revenue	—	—	4,026	—	—	—	4,026
Electricity and transmission revenue	—	—	—	177	—	—	177
Total revenue from contracts with customers	9,639	4,668	4,948	177	—	—	19,432
Commodity sales	—	—	—	—	26,873	—	26,873
Other revenue[1,2]	375	42	13	336	—	—	766
Intersegment revenue	567	1	19	(1)	44	(630)	—
Total revenue	10,581	4,711	4,980	512	26,917	(630)	47,071

Year ended December 31, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	9,161	4,523	674	—	—	—	14,358
Storage and other revenue	94	274	203	—	—	—	571
Gas gathering and processing revenue	—	27	—	—	—	—	27
Gas distribution revenue	—	—	3,663	—	—	—	3,663
Electricity and transmission revenue	—	—	—	198	—	—	198
Total revenue from contracts with customers	9,255	4,824	4,540	198	—	—	18,817
Commodity sales	—	—	—	—	19,259	—	19,259
Other revenue[1,2]	584	44	17	389	—	(23)	1,011
Intersegment revenue	584	2	12	—	24	(622)	—
Total revenue	10,423	4,870	4,569	587	19,283	(645)	39,087

1 *Includes mark-to-market losses from our hedging program for the year ended December 31, 2022 of $431 million (2021 - $59 million gain; 2020 - $265 million gain).*
2 *Includes revenues from lease contracts. Refer to* Note 27 - Leases.

We disaggregate revenue into categories which represent our principal performance obligations within each business segment. These revenue categories represent the most significant revenue streams in each segment and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Contract Receivables	Contract Assets	Contract Liabilities
(millions of Canadian dollars)			
Balance as at December 31, 2022	**3,183**	**230**	**2,241**
Balance as at December 31, 2021	2,369	213	1,898

Contract receivables represent the amount of receivables derived from contracts with customers.

Contract assets represent the amount of revenue which has been recognized in advance of payments received for performance obligations we have fulfilled (or have partially fulfilled) and prior to the point in time at which our right to the payment is unconditional. Amounts included in contract assets are transferred to accounts receivable when our right to the consideration becomes unconditional.

Contract liabilities represent payments received for performance obligations which have not been fulfilled. Contract liabilities primarily relate to make-up rights and deferred revenue. Revenue recognized during the year ended December 31, 2022 included in contract liabilities at the beginning of the year is $166 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2022, were $453 million.

Performance Obligations

Segment	Nature of Performance Obligation
Liquids Pipelines	• Transportation and storage of crude oil and natural gas liquids (NGL)
Gas Transmission and Midstream	• Transportation, storage, gathering, compression and treating of natural gas • Transportation of NGL • Sale of crude oil, natural gas and NGL
Gas Distribution and Storage	• Supply and delivery of natural gas • Transportation of natural gas • Storage of natural gas
Renewable Power Generation	• Generation and transmission of electricity • Delivery of electricity from renewable energy generation facilities

There was no material revenue recognized during the year ended December 31, 2022 from performance obligations satisfied in previous periods.

Payment Terms

Payments are received monthly from customers under long-term transportation, commodity sales, and gas gathering and processing contracts. Payments from Gas Distribution and Storage customers are received on a continuous basis based on established billing cycles.

Certain contracts in our US offshore business provide for us to receive a series of fixed monthly payments (FMPs) for a specified period that is less than the period during which the performance obligations are satisfied. As a result, a portion of the FMPs are recorded as contract liabilities. The FMPs are not considered to be a financing arrangement as payments are scheduled to match the production profiles of offshore oil and gas fields, which generate greater revenue in the initial years of their productive lives.

Revenue to be Recognized from Unfulfilled Performance Obligations
Total revenue from performance obligations expected to be fulfilled in future periods is $58.6 billion, of which $7.6 billion is expected to be recognized during the year ending December 31, 2023.

The revenues excluded from the amounts above based on optional exemptions available under Accounting Standards Codification (ASC) 606, as explained below, represent a significant portion of our overall revenues and revenues from contracts with customers. Certain revenues such as flow-through operating costs charged to shippers are recognized at the amount for which we have the right to invoice our customers and are excluded from the amounts of revenue to be recognized in the future from unfulfilled performance obligations above. Variable consideration is excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. Additionally, the effect of escalation on certain tolls which are contractually escalated for inflation has not been reflected in the amounts above as it is not possible to reliably estimate future inflation rates. Revenues for periods extending beyond the current rate settlement term for regulated contracts where the tolls are periodically reset by the regulator are excluded from the amounts above since future tolls remain unknown. Finally, revenues from contracts with customers which have an original expected duration of one year or less are excluded from the amounts above.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE
Long-Term Transportation Agreements
For long-term transportation agreements, significant judgments pertain to the period over which revenue is recognized and whether the agreement provides for make-up rights for the shippers. Transportation revenue earned from firm contracted capacity arrangements is recognized ratably over the contract period. Transportation revenue from interruptible or volumetric-based arrangements is recognized when services are performed.

Variable Consideration
Revenue from arrangements subject to variable consideration is recognized only to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved. Uncertainties associated with variable consideration relate principally to differences between estimated and actual volumes and prices. These uncertainties are resolved each month when actual volumes are sold or transported and actual tolls and prices are determined.

During the year ended December 31, 2022, revenue for the Canadian Mainline has been recognized in accordance with the terms of the Competitive Toll Settlement (CTS), which expired on June 30, 2021. The tolls in place on June 30, 2021 continue on an interim basis until a new commercial arrangement is implemented and are subject to finalization and adjustment applicable to the interim period, if any. Due to the uncertainty of adjustment to tolling pursuant to a CER decision and potential customer negotiations, interim toll revenue recognized during the year ended December 31, 2022 is considered variable consideration.

Recognition and Measurement of Revenue

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	**—**	**—**	**127**	**—**	**127**
Revenue from products and services transferred over time[1]	**11,518**	**5,384**	**6,606**	**281**	**23,789**
Total revenue from contracts with customers	**11,518**	**5,384**	**6,733**	**281**	**23,916**

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	—	—	70	—	70
Revenue from products and services transferred over time[1]	9,639	4,668	4,878	177	19,362
Total revenue from contracts with customers	9,639	4,668	4,948	177	19,432

Year ended December 31, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	—	—	60	—	60
Revenue from products and services transferred over time[1]	9,255	4,824	4,480	198	18,757
Total revenue from contracts with customers	9,255	4,824	4,540	198	18,817

1 Revenue from crude oil and natural gas pipeline transportation, storage, natural gas gathering, compression and treating, natural gas distribution, natural gas storage services and electricity sales.

Performance Obligations Satisfied Over Time
For arrangements involving the transportation and sale of petroleum products and natural gas where the transportation services or commodities are simultaneously received and consumed by the shipper or customer, we recognize revenue over time using an output method based on volumes of commodities delivered or transported. The measurement of the volumes transported or delivered corresponds directly to the benefits received by the shippers or customers during that period.

Determination of Transaction Prices
Prices for transportation and gas processing services are determined based on the capital cost of the facilities, pipelines and associated infrastructure required to provide such services, plus a rate of return on capital invested that is determined either through negotiations with customers or through regulatory processes for those operations that are subject to rate regulation.

Prices for commodities sold are determined by reference to market price indices, plus or minus a negotiated differential and in certain cases a marketing fee.

Prices for natural gas sold and distribution services provided by regulated natural gas distribution operations are prescribed by regulation.

5. SEGMENTED INFORMATION

Segmented information for the years ended December 31, 2022, 2021 and 2020 is as follows:

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues *(Note 4)*	**12,052**	**5,426**	**6,729**	**582**	**29,175**	**(655)**	**53,309**
Commodity and gas distribution costs	**—**	**—**	**(3,693)**	**(16)**	**(29,525)**	**645**	**(32,589)**
Operating and administrative	**(4,287)**	**(2,254)**	**(1,289)**	**(255)**	**(49)**	**(85)**	**(8,219)**
Impairment of long-lived assets	**(245)**	**—**	**—**	**(235)**	**(13)**	**(48)**	**(541)**
Impairment of goodwill *(Note 16)*	**—**	**(2,465)**	**—**	**—**	**—**	**—**	**(2,465)**
Income/(loss) from equity investments *(Note 13)*	**785**	**1,133**	**1**	**141**	**—**	**(4)**	**2,056**
Gain on joint venture merger transaction *(Note 13)*	**—**	**1,076**	**—**	**—**	**—**	**—**	**1,076**
Other income/(expense) *(Note 28)*	**59**	**210**	**79**	**45**	**(5)**	**(977)**	**(589)**
Earnings/(loss) before interest, income taxes and depreciation and amortization	**8,364**	**3,126**	**1,827**	**262**	**(417)**	**(1,124)**	**12,038**
Depreciation and amortization							**(4,317)**
Interest expense *(Note 18)*							**(3,179)**
Income tax expense *(Note 25)*							**(1,604)**
Earnings							**2,938**
Capital expenditures[1]	**1,418**	**1,690**	**1,499**	**50**	**—**	**33**	**4,690**
Total property, plant and equipment, net *(Note 11)*	**53,567**	**29,666**	**17,857**	**3,082**	**6**	**282**	**104,460**

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues *(Note 4)*	10,581	4,711	4,980	512	26,917	(630)	47,071
Commodity and gas distribution costs	(25)	—	(2,147)	—	(27,174)	644	(28,702)
Operating and administrative	(3,431)	(1,877)	(1,143)	(180)	(48)	(33)	(6,712)
Income/(loss) from equity investments *(Note 13)*	759	813	42	101	—	(4)	1,711
Impairment of equity investments *(Note 13)*	—	(111)	—	—	—	—	(111)
Other income/(expense) *(Note 28)*	13	135	385	75	(8)	379	979
Earnings/(loss) before interest, income taxes and depreciation and amortization	7,897	3,671	2,117	508	(313)	356	14,236
Depreciation and amortization							(3,852)
Interest expense *(Note 18)*							(2,655)
Income tax expense *(Note 25)*							(1,415)
Earnings							6,314
Capital expenditures[1]	4,051	2,420	1,343	16	1	54	7,885
Total property, plant and equipment, net *(Note 11)*	52,530	27,028	16,904	3,315	23	267	100,067

Year ended December 31, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues *(Note 4)*	10,423	4,870	4,569	587	19,283	(645)	39,087
Commodity and gas distribution costs	(20)	—	(1,810)	(2)	(19,450)	613	(20,669)
Operating and administrative	(3,331)	(1,859)	(1,091)	(191)	(67)	(210)	(6,749)
Income/(loss) from equity investments *(Note 13)*	558	479	9	94	(3)	(1)	1,136
Impairment of equity investments *(Note 13)*	—	(2,351)	—	—	—	—	(2,351)
Other income/(expense) *(Note 28)*	53	(52)	71	35	1	130	238
Earnings/(loss) before interest, income taxes and depreciation and amortization	7,683	1,087	1,748	523	(236)	(113)	10,692
Depreciation and amortization							(3,712)
Interest expense *(Note 18)*							(2,790)
Income tax expense *(Note 25)*							(774)
Earnings							3,416
Capital expenditures[1]	2,033	2,130	1,134	81	2	90	5,470
Total property, plant and equipment, net	48,799	25,745	16,079	3,495	24	429	94,571

1 Includes allowance for equity funds used during construction.

The measurement basis for preparation of segmented information is consistent with the significant accounting policies *(Note 2)*.

GEOGRAPHIC INFORMATION
Revenues[1]

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Canada	**27,498**	20,474	16,453
US	**25,811**	26,597	22,634
	53,309	47,071	39,087

1 Revenues are based on the country of origin of the product or service sold.

Property, Plant and Equipment[1]

December 31,	**2022**	2021
(millions of Canadian dollars)		
Canada	**47,602**	47,102
US	**56,858**	52,965
	104,460	100,067

1 Amounts are based on the location where the assets are held.

6. EARNINGS PER COMMON SHARE

BASIC
Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. On December 30, 2021, we closed the sale of our minority ownership in Noverco. The weighted average number of common shares outstanding was reduced by our pro-rata weighted average interest in our own common shares of approximately 2 million and 5 million as at December 31, 2021 and 2020, respectively, resulting from our reciprocal investment in Noverco.

DILUTED
The treasury stock method is used to determine the dilutive impact of stock options and RSUs. This method assumes any proceeds from the exercise of stock options and vesting of RSUs would be used to purchase common shares at the average market price during the period.

Weighted average shares outstanding used to calculate basic and diluted earnings per share are as follows:

December 31,	**2022**	2021	2020
(number of shares in millions)			
Weighted average shares outstanding	**2,025**	2,023	2,020
Effect of dilutive options and RSUs	**4**	2	1
Diluted weighted average shares outstanding	**2,029**	2,025	2,021

For the years ended December 31, 2022, 2021 and 2020, 10.4 million, 18.6 million and 29.8 million, respectively, of anti-dilutive stock options with a weighted average exercise price of $56.49, $52.89 and $51.42, respectively, were excluded from the diluted earnings per common share calculation.

7. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under US GAAP for non-regulated entities. See *Note 2 - Significant Accounting Policies* for further discussion. Our significant regulated businesses and the related accounting impacts are described below.

Under the current authorized rate structure for certain operations, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of temporary differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since most of these temporary differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of the related assets. In the absence of rate-regulated accounting, this regulatory Deferred income taxes balance and the related earnings impact would not be recorded.

LIQUIDS PIPELINES

Canadian Mainline

Canadian Mainline includes the Canadian portion of our mainline system and is subject to regulation by the CER. Tolls, excluding Lines 8 and 9, are governed by the 10-year CTS which expired on June 30, 2021. The tolls in place on June 30, 2021 continue on an interim basis until new tolls are finalized and approved by the CER *(Note 4).* The CTS established a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on our Lakehead System. Under the CTS, we have recognized a regulatory asset of $2.1 billion as at December 31, 2022 (2021 - $2.1 billion) to offset deferred income taxes, as a CER rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the CTS.

Southern Lights Pipeline

The US and Canadian portions of the Southern Lights Pipeline are regulated by the FERC and CER, respectively. Shippers on the Southern Lights Pipeline are subject to long-term transportation contracts under a cost-of-service toll methodology. Toll adjustments are filed annually with the regulators and provide for the recovery of allowable operating and debt financing costs, plus a pre-determined after-tax return on equity (ROE) of 10%.

GAS TRANSMISSION AND MIDSTREAM

British Columbia Pipeline and Maritimes & Northeast Canada

British Columbia (BC) Pipeline and Maritimes & Northeast (M&N) Canada are regulated by the CER. Rates are approved by the CER through negotiated toll settlement agreements based on cost-of-service. Both our BC Pipeline and M&N Canada systems currently operate under the terms of their respective 2022-2026 and 2022-2023 settlement agreements, which stipulate an allowable ROE and the continuation and establishment of certain deferral and variance accounts.

US Gas Transmission

Most of our US gas transmission and storage services are regulated by the FERC and may also be subject to the jurisdiction of various other federal, state and local agencies. The FERC regulates natural gas transmission in US interstate commerce including the establishment of rates for services, while rates for intrastate commerce and/or gathering services are regulated by the state agencies. Cost-of-service is the basis for the calculation of regulated tariff rates, although the FERC also allows the use of negotiated and discounted rates within contracts with shippers that may result in a rate that is above or below the FERC-regulated recourse rate for that service.

GAS DISTRIBUTION AND STORAGE

Enbridge Gas

Enbridge Gas' distribution rates, commencing in 2019, are set under a five-year Incentive Regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved ROE.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following regulatory assets and liabilities in the Consolidated Statements of Financial Position.

December 31,	**2022**	2021	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Purchase gas variance	**190**	15	2023
Under-recovery of fuel costs	**109**	114	2023
Other current regulatory assets	**305**	130	2023
Total current regulatory assets[1] *(Note 9)*	**604**	259	
Long-term regulatory assets			
Deferred income taxes[2]	**4,473**	4,176	Various
Long-term debt[3]	**378**	398	2032-2046
Negative salvage[4]	**265**	243	Various
Purchase gas variance	**244**	215	2024
Accounting policy changes[5]	**219**	157	Various
Pension plan receivable[6]	**40**	78	Various
Other long-term regulatory assets	**244**	339	Various
Total long-term regulatory assets[1]	**5,863**	5,606	
Total regulatory assets	**6,467**	5,865	
Current regulatory liabilities			
Other current regulatory liabilities	**167**	106	2023
Total current regulatory liabilities[7]	**167**	106	
Long-term regulatory liabilities			
Future removal and site restoration reserves[8]	**1,615**	1,543	Various
Regulatory liability related to US income taxes[9]	**918**	895	2050-2072
Pipeline future abandonment costs *(Note 14)*	**610**	649	Various
Pension plan payable[6]	**231**	—	Various
Other long-term regulatory liabilities	**250**	234	Various
Total long-term regulatory liabilities[7]	**3,624**	3,321	
Total regulatory liabilities	**3,791**	3,427	

1 Current regulatory assets are included in Accounts receivable and other, while long-term regulatory assets are included in Deferred amounts and other assets.
2 Represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in future regulator-approved rates and recovered from customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded.
3 Represents our regulatory offset to the fair value adjustment to debt acquired in our merger with Spectra Energy Corp. (Spectra Energy). The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.
4 The negative salvage balance represents the recovery in future rates of the actual cost of removal of previously retired or decommissioned plant assets, as approved by the FERC.
5 This deferral primarily consists of unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas Limited, relating to the period up to our merger with Spectra Energy, which were previously recorded in AOCI. The amortization of this balance is recognized as a component of accrual-based pension expenses, which are included in Other income/(expense) and recovered in rates, as previously approved by the OEB.
6 Represents the regulatory offset to our pension liability to the extent that it is expected to be included in regulator-approved future rates and recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense would be recorded in earnings and OCI.
7 Current regulatory liabilities are included in Accounts payable and other, while long-term regulatory liabilities are included in Other long-term liabilities.

8 *Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

9 *The regulatory liability related to US income taxes resulted from the US tax reform legislation dated December 22, 2017. These balances will be refunded to customers in accordance with the respective rate settlements approved by the FERC.*

8. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

Tri Global Energy, LLC

On September 27, 2022, through a wholly-owned US subsidiary, we acquired all of the outstanding common units in TGE for cash consideration of $295 million (US$215 million) plus potential contingent payments of up to $72 million (US$53 million) dependent on the achievement of performance milestones by TGE (the TGE Acquisition). The TGE Acquisition is subject to customary closing and working capital adjustments. TGE is an onshore renewable project developer in the US with a development portfolio of wind and solar projects. The TGE Acquisition enhances Enbridge's renewable power platform and accelerates our North American growth strategy.

We accounted for the TGE Acquisition using the acquisition method as prescribed by ASC 805 *Business Combinations*. In accordance with valuation methodologies described in ASC 820 *Fair Value Measurements*, the acquired assets and assumed liabilities are recorded at their estimated fair values as at the date of acquisition.

The following table summarizes the estimated fair values that were assigned to the net assets of TGE:

	September 27, 2022
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	**5**
Property, plant and equipment	**3**
Long-term investments	**8**
Intangible assets (a)	**117**
Long-term assets	**3**
Current liabilities	**61**
Long-term debt *(Note 18)*	**18**
Long-term liabilities (b)	**105**
Goodwill (c)	**392**
Purchase price:	
Cash	**295**
Contingent consideration (d)	**49**
	344

a) Intangible assets consist of compensation expected to be earned by TGE on existing development contracts once certain project development milestones are met. Fair value was determined using a discounted cash flow method which is an income-based approach to valuation that estimates the present value of future projected benefits from the contracts. The intangible assets will be amortized on a straight-line basis over an expected useful life of three and a half years.

b) Long-term liabilities consist primarily of obligations payable to third parties which are contingent on the timing of milestones being met for certain projects. Fair value represents the present value of the future cash flow payments at the date of the TGE Acquisition.

c) Goodwill is primarily attributable to expected future returns from new opportunities to develop wind and solar projects, as well as enhanced scale and operational diversity of our renewable projects portfolio. The goodwill balance recognized has been assigned to our Renewable Power Generation segment and is tax deductible over 15 years.

d) We agreed to pay additional contingent consideration of up to US$53 million to TGE's former common unit holders if performance milestones are met on certain projects. The US$36 million of contingent consideration recognized in the purchase price represents the fair value of contingent consideration at the date of acquisition. The fair value was determined using an income-based approach.

Upon completion of the TGE Acquisition, we began consolidating TGE. For the period beginning September 27, 2022 through to December 31, 2022, operating revenues and earnings attributable to common shareholders generated by TGE were immaterial. The impact to our supplemental pro forma consolidated operating revenues and earnings attributable to common shareholders for the years ended December 31, 2022 and 2021, as if the TGE Acquisition had been completed on January 1, 2021, was also immaterial.

Moda Midstream Operating, LLC
On October 12, 2021, through a wholly-owned US subsidiary, we acquired all of the outstanding membership interests in Moda for $3.7 billion (US$3.0 billion) of cash plus potential contingent payments of up to US$150 million dependent on performance of the assets (the Moda Acquisition). The Moda Acquisition was also subject to customary closing and working capital adjustments. Moda owns and operates a light crude export platform with very large crude carrier capability. The Moda Acquisition aligns with and advances our US Gulf Coast export strategy and enables connectivity to low-cost and long-lived reserves in the Permian and Eagle Ford basins.

We accounted for the Moda Acquisition using the acquisition method as prescribed by ASC 805 *Business Combinations*. In accordance with valuation methodologies described in ASC 820 *Fair Value Measurements*, the acquired assets and assumed liabilities were recorded at their estimated fair values as at the date of acquisition.

The following table summarizes the estimated fair values that were assigned to the net assets of Moda:

	October 12, 2021
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	62
Property, plant and equipment (a)	1,480
Long-term investments (b)	427
Intangible assets (c)	1,781
Current liabilities	59
Long-term liabilities	17
Goodwill (d)	268
Purchase price:	
Cash	3,755
Contingent consideration (e)	187
	3,942

a) Due to the specialized nature of Moda's property, plant and equipment, which includes groups of assets configured for use as storage facilities, pipelines and export terminals, the depreciated replacement cost approach was adopted as the primary valuation methodology. In determining replacement cost, both indirect costing using relevant inflation indices and direct costing using relevant market quotes were utilized. Adjustments were then applied for physical deterioration as well as functional and economic obsolescence. The fair value of land was determined using a market approach, which is based on rents and offerings for comparable properties.

b) Long-term investments represent Moda's 20% equity interest in Cactus II Pipeline LLC (Cactus II). The fair value of Cactus II was determined using the discounted cash flow method. The discounted cash flow method is an income-based approach to valuation which estimates the present value of future projected benefits from the investment.

c) Intangible assets consist primarily of customer relationships associated with long-term take-or-pay contracts. Fair value was determined using an income-based approach by estimating the present value of the after-tax earnings attributable to the contracts, including earnings associated with expected renewal terms, and will be amortized on a straight-line basis over an expected useful life of 10 years.

d) Goodwill is primarily attributable to uncontracted future revenues, existing assembled assets that cannot be duplicated at the same cost by a new entrant, and enhanced scale and geographic diversity which provide greater optionality and platforms for future growth. The goodwill balance recognized has been assigned to our Liquids Pipelines segment and is tax deductible over 15 years.

e) We agreed to pay additional contingent consideration of up to US$150 million to Moda's former membership interest holders if Moda's monthly volumes of crude oil loaded onto a vessel equal or exceed specified throughput levels. These performance requirements terminate the earlier of December 31, 2023 or the date the final contingent payment is made. The US$150 million of contingent consideration recognized in the purchase price represents the fair value of contingent consideration at the date of acquisition and was fully settled as at December 31, 2022.

Acquisition-related expenses incurred were approximately $21 million for the year ended December 31, 2021 and are included in Operating and administrative expense in the Consolidated Statements of Earnings.

Upon completion of the Moda Acquisition, we began consolidating Moda. For the period beginning October 12, 2021 through to December 31, 2021, Moda generated approximately $80 million in operating revenues and $9 million in earnings attributable to common shareholders.

Our supplemental pro forma consolidated financial information for the years ended December 31, 2021 and 2020, including the results of operations for Moda as if the Moda Acquisition had been completed on January 1, 2020, are as follows:

Year ended December 31,	2021	2020
(unaudited; millions of Canadian dollars)		
Operating revenues	47,339	39,435
Earnings attributable to common shareholders[1,2]	5,771	2,938

1 Acquisition-related expenses of $21 million (after-tax $16 million) were excluded from earnings attributable to common shareholders for the year ended December 31, 2021 and deducted for the year ended December 31, 2020.
2 Includes the amortization of fair value adjustments recorded for acquired property, plant and equipment, long-term investments and intangible assets of $193 million and $207 million (after-tax of $145 million and $155 million) for the years ended December 31, 2021 and 2020, respectively.

DISPOSITIONS

Athabasca Regional Oil Sands System

On October 5, 2022, we closed the sale of an 11.6% non-operating interest in seven pipelines in the Athabasca region of northern Alberta from our Regional Oil Sands System to Athabasca Indigenous Investments Limited Partnership (Aii), an entity representing 23 First Nation and Métis communities, for total consideration of approximately $1.1 billion, less customary closing adjustments. No gain or loss was recognized on the sale and a noncontrolling interest was recorded in our Consolidated Statements of Financial Position as at December 31, 2022 to reflect the interest held by Aii *(Note 20)*.

Subsequent to the sale, we maintained an 88.4% controlling interest in these assets, which are a component of our Liquids Pipelines segment, and continue to manage, operate and provide administrative services to them.

Line 10 Crude Oil Pipeline

In the first quarter of 2018, we satisfied the condition as set out in our agreements for the sale of our Line 10 crude oil pipeline (Line 10), which originates near Hamilton, Ontario and terminates at West Seneca, New York. Our subsidiaries, Enbridge Pipelines Inc. and Enbridge Energy Partners, L.P. owned the Canadian and US portions of Line 10, respectively, and the related assets were included in our Liquids Pipelines segment. The transaction closed on June 1, 2020. No gain or loss on disposition was recorded.

Montana-Alberta Tie Line

On May 1, 2020, we closed the sale of the Montana-Alberta Tie Line (MATL) transmission asset, a 345 kilometer transmission line from Great Falls, Montana to Lethbridge, Alberta, for cash proceeds of approximately $189 million. After closing adjustments, a gain on disposal of $4 million was included in Other income/(expense) in the Consolidated Statements of Earnings. MATL was included in our Renewable Power Generation segment.

Ozark Gas Transmission

On April 1, 2020, we closed the sale of our Ozark Gas Transmission and Ozark Gas Gathering assets (Ozark assets) for cash proceeds of approximately $63 million. After closing adjustments, a gain on disposal of $1 million was included in Other income/(expense) in the Consolidated Statements of Earnings. The Ozark assets are composed of a transmission system that extends from southeastern Oklahoma through Arkansas to southeastern Missouri, and a fee-based gathering system that accesses Fayetteville Shale and Arkoma production. These assets were included in our Gas Transmission and Midstream segment.

9. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2022**	2021
(millions of Canadian dollars)		
Trade receivables and unbilled revenues[1]	**5,616**	4,957
Short-term portion of derivative assets *(Note 24)*	**1,015**	529
Regulatory assets *(Note 7)*	**604**	259
Gas imbalance	**461**	276
Taxes receivable	**323**	407
Other	**852**	434
	8,871	6,862

1 Net of allowance for expected credit losses of $92 million and $87 million as at December 31, 2022 and 2021, respectively.

10. INVENTORY

December 31,	2022	2021
(millions of Canadian dollars)		
Natural gas	**1,491**	953
Crude oil	**652**	624
Other	**112**	93
	2,255	1,670

11. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	2022	2021
(millions of Canadian dollars)			
Pipelines	2.9 %	**66,528**	62,997
Facilities and equipment	3.5 %	**37,028**	34,331
Land and right-of-way[1]	2.2 %	**3,637**	3,320
Gas mains, services and other	2.6 %	**14,491**	13,606
Storage	2.3 %	**3,477**	3,099
Wind turbines, solar panels and other	4.1 %	**4,912**	4,912
Other	8.5 %	**1,611**	1,507
Under construction	— %	**2,316**	2,268
Total property, plant and equipment		**134,000**	126,040
Total accumulated depreciation		**(29,540)**	(25,973)
Property, plant and equipment, net		**104,460**	100,067

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.

Depreciation expense for the years ended December 31, 2022, 2021 and 2020 was $3.8 billion, $3.5 billion and $3.4 billion, respectively.

IMPAIRMENT

Magic Valley Wind Farm

Magic Valley Wind Farm (Magic Valley) has commercial challenges caused by electricity transmission congestion and a negative price differential arising from higher transmission costs resulting in a lower electricity sale price. As a result, we have recognized an impairment loss of $227 million to our investment in Magic Valley, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Renewable Power Generation segment.

Bakken Pipeline System

The Bakken Pipeline System currently has long-term take-or-pay contracts that are set to expire in 2023. In connection with the upcoming expiration of the contracts, we have recognized an impairment loss of $183 million on the US and Canadian components of the interstate pipeline transportation system within the North Dakota System of our Bakken System, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Liquids Pipelines segment.

Impairment charges were based on the amount by which the carrying value of the assets exceeded fair value, determined using expected discounted future cash flows.

12. VARIABLE INTEREST ENTITIES

CONSOLIDATED VARIABLE INTEREST ENTITIES

Our consolidated VIEs consist of legal entities where we are the primary beneficiary. We are the primary beneficiary when our variable interest(s) provide us with (i) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (ii) the obligation to absorb losses of the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. We determine whether we are the primary beneficiary of a VIE by considering qualitative and quantitative factors, including, but not limited to: decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties.

The following table includes assets to be used to settle liabilities of our consolidated VIEs. The creditors of the liabilities of our consolidated VIEs do not have recourse to our general credit as the primary beneficiary. These assets and liabilities are included in the Consolidated Statements of Financial Position.

December 31,	**2022**[1]	2021
(millions of Canadian dollars)		
Assets		
Cash and cash equivalents	**426**	247
Restricted cash	**12**	4
Accounts receivable and other	**199**	99
Accounts receivable from affiliates	**23**	—
Inventory	**12**	9
	672	359
Property, plant and equipment, net	**7,707**	3,052
Long-term investments	**14**	16
Restricted long-term investments	**98**	101
Deferred amounts and other assets	**158**	2
Intangible assets, net	**102**	108
	8,751	3,638
Liabilities		
Accounts payable and other	**251**	84
Accounts payable to affiliates	**21**	—
	272	84
Other long-term liabilities	**859**	182
Deferred income taxes	**5**	5
	1,136	271
	7,615	3,367

1 *Includes assets and liabilities of newly created Enbridge Athabasca Midstream Trunkline LP and Enbridge Athabasca Midstream Investor LP following the sale of a minority interest in certain Athabasca Regional Oil Sands System assets. Refer to* Note 8 - Acquisitions and Dispositions.

We do not have obligations to provide additional financial support to any of our consolidated VIEs.

UNCONSOLIDATED VARIABLE INTEREST ENTITIES

We currently hold interests in several non-consolidated VIEs where we are not the primary beneficiary as we do not have the power to direct the activities of the VIEs that most significantly impact their economic performance. These interests include investments in limited partnerships that are assessed to be VIEs due to the limited partners not having substantive kick-out rights or participating rights. The power to direct the activities of a majority of these non-consolidated limited partnership VIEs is shared amongst the partners. Each partner has representatives that make up an executive committee that makes significant decisions for the VIE, and none of the partners may make significant decisions unilaterally.

The carrying amount of these VIEs and our estimated maximum exposure to loss as at December 31, 2022 and 2021 are presented below:

December 31, 2022	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[1]	**91**	**117**
EIH S.á r.l.[2]	**37**	**637**
Rampion Offshore Wind Limited[3]	**413**	**468**
Vector Pipeline L.P.[4]	**195**	**325**
Woodfibre LNG Limited Partnership[5,6]	**635**	**2,476**
Other[7]	**245**	**443**
	1,616	**4,466**

December 31, 2021	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[1]	113	195
EIH S.á r.l.[2]	38	664
Enbridge Renewable Infrastructure Investments S.á r.l.[8,9]	54	2,121
Rampion Offshore Wind Limited[3]	450	508
Vector Pipeline L.P.[4]	189	374
Other[7]	210	426
	1,054	4,288

1 *As at December 31, 2022 and 2021, the maximum exposure to loss includes a guarantee by us for our respective share of the VIE's borrowing on a bank credit facility.*
2 *As at December 31, 2022 and 2021, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the three French offshore wind projects for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $56 million and $73 million held by us as at December 31, 2022 and 2021, respectively.*
3 *As at December 31, 2022 and 2021, the maximum exposure to loss includes our parental guarantees that have been committed in project contracts in which we would be liable for in the event of default by the VIE.*
4 *As at December 31, 2022 and 2021, the maximum exposure to loss includes the carrying value of outstanding affiliate loans receivable for $25 million and $80 million held by us as at December 31, 2022 and 2021, respectively, and an outstanding credit facility for $105 million as at December 31, 2022 and 2021.*
5 *In November 2022, Enbridge acquired a 30% interest in Woodfibre LNG Limited Partnership (Woodfibre). Refer to* Note 13 - Long-Term Investments. *Woodfibre is a VIE due to its lack of sufficient equity at risk to finance its activities. Enbridge does not hold decision-making rights to direct Woodfibre's activities that most significantly impact its economic performance.*
6 *As at December 31, 2022, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the project for which we would be liable in the event of default by the VIE.*
7 *As at December 31, 2022 and 2021, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the projects for which we would be liable in the event of default by the VIE.*
8 *As at December 31, 2021, the maximum exposure to loss included our parental guarantees that have been committed in connection with the project for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $807 million held by us as at December 31, 2021.*
9 *Following a reconsideration event in connection with an additional equity injection to facilitate debt and equity rebalancing of Enbridge Renewable Infrastructure Investments S.á r.l. (ERII) in the third quarter of 2022, ERII's equity is now sufficient for it to finance its activities without additional subordinated financial support. Therefore, it is no longer considered to be a VIE.*

We do not have an obligation to and did not provide any additional financial support to the VIEs during the years ended December 31, 2022 and 2021.

13. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2022**	2021
(millions of Canadian dollars)			
EQUITY INVESTMENTS			
Liquids Pipelines			
MarEn Bakken Company LLC[1]	75.0 %	**1,968**	1,752
DCP Midstream, LLC (Class B Units)[2]	90.0 %	**1,394**	469
Seaway Crude Holdings LLC	50.0 %	**2,744**	2,634
Illinois Extension Pipeline Company, L.L.C.[3]	65.0 %	**622**	593
Cactus II Pipeline LLC[4]	30.0 %	**658**	434
Other	30.0% - 43.8%	**76**	71
Gas Transmission and Midstream			
Alliance Pipeline[5]	50.0 %	**430**	504
Aux Sable[6]	42.7% - 50.0%	**214**	238
DCP Midstream, LLC (Class A Units)[7]	23.4 %	**317**	397
Gulfstream Natural Gas System, L.L.C.	50.0 %	**1,274**	1,180
Nexus Gas Transmission, LLC	50.0 %	**1,813**	1,724
Sabal Trail Transmission, LLC	50.0 %	**1,535**	1,464
Southeast Supply Header, LLC	50.0 %	**86**	82
Steckman Ridge, LP	50.0 %	**91**	88
Vector Pipeline[8]	60.0 %	**195**	189
Woodfibre LNG Limited Partnership	30.0 %	**635**	—
Offshore - various joint ventures	22.0% - 74.3%	**314**	309
Other	20.0% - 33.3%	**—**	14
Gas Distribution and Storage			
Other	47.6% - 50.0%	**20**	20
Renewable Power Generation			
EIH S.à.r.l.[9]	51.0 %	**37**	38
Enbridge Renewable Infrastructure Investments S.à.r.l.	51.0 %	**163**	54
Rampion Offshore Wind Limited	24.9 %	**413**	450
NextBridge Infrastructure LP	25.0 %	**241**	186
Other	15.8% - 50.0%	**107**	92
OTHER LONG-TERM INVESTMENTS			
Gas Transmission and Midstream			
Fairwood Peninsula Energy Corporation		**22**	20
Gas Distribution and Storage			
Oakville Enterprises Corporation[10]		**48**	—
Renewable Power Generation			
Emerging Technologies and Other		**31**	32
Eliminations and Other			
Other[11]		**488**	290
		15,936	13,324

1 *Owns a 49.0% interest in Bakken Pipeline Investments L.L.C. Bakken Pipeline Investments L.L.C. owns 75.0% of the Bakken Pipeline System, resulting in a 27.6% effective interest in the Bakken Pipeline System by us.*
2 *We own 90.0% of the Class B units of DCP Midstream, LLC. These units track to a 65.0% ownership in Gray Oak Pipeline, LLC (Gray Oak), resulting in a 58.5% effective interest in Gray Oak by us. In 2021, we owned a 35.0% interest in Gray Oak Holdings LLC, which owned a 65.0% interest in Gray Oak, resulting in a 22.8% effective interest in Gray Oak by us.*
3 *Owns the Southern Access Extension Project.*
4 *On October 12, 2021, we acquired an effective 20.0% interest in Cactus II through the acquisition of Moda. Refer to* Note 8 - Acquisitions and Dispositions *for further discussion. On November 2, 2022, we acquired an additional 10.0% ownership in Cactus II for cash payment of $241 million (US$177 million), bringing our total non-operating ownership to 30.0%.*
5 *Includes Alliance Pipeline Limited Partnership in Canada and Alliance Pipeline L.P. in the US.*
6 *Includes Aux Sable Canada LP in Canada and Aux Sable Liquid Products LP and Aux Sable Midstream LLC in the US.*

7 We own 23.4% of the Class A units of DCP Midstream, LLC. These units track to a 56.5% ownership in DCP Midstream, LP (DCP), resulting in a 13.2% effective interest in DCP by us. In 2021, we owned an effective 28.3% interest in DCP.
8 Includes Vector Pipeline Limited Partnership in Canada and Vector Pipeline L.P. in the US.
9 On March 18, 2021, we sold 49.0% of EIH S.à.r.l., an entity that holds our 50.0% interest in Éolien Maritime France SAS (EMF), to the Canada Pension Plan Investment Board. This resulted in a 25.5% effective interest in EMF. Through our investment in EMF, we own equity interests in three French offshore wind projects, including effective interests in Saint-Nazaire (25.5%), Fécamp (17.9%) and Calvados (21.7%).
10 On August 2, 2022, we acquired a 10.0% interest in Oakville Enterprises Corporation.
11 Consists of investments in debt and equity securities held by our wholly-owned captive insurance subsidiaries. Refer to Note 24 -Risk Management and Financial Instruments.

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date. As at December 31, 2022, this basis difference was $3.4 billion (2021 - $2.5 billion), of which $1.5 billion (2021 - $730 million) was amortizable.

For the years ended December 31, 2022, 2021 and 2020, distributions received from equity investments were $2.6 billion, $2.2 billion and $2.1 billion, respectively.

Summarized combined financial information of our interest in unconsolidated equity investments (presented at 100%) is as follows:

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating revenues	**27,043**	20,021	14,096
Operating expenses	**23,043**	16,706	12,411
Earnings	**4,334**	3,022	2,324
Earnings attributable to Enbridge	**2,056**	1,711	1,136

December 31,	**2022**	2021
(millions of Canadian dollars)		
Current assets	**4,196**	3,639
Non-current assets	**53,405**	44,863
Current liabilities	**4,843**	3,741
Non-current liabilities	**18,595**	16,979
Noncontrolling interests	**3,785**	3,786

DCP Midstream, LLC
On August 17, 2022, we completed a joint venture merger transaction with Phillips 66 (P66) resulting in a single joint venture, DCP Midstream, LLC, holding both our and P66's indirect ownership interests in Gray Oak and DCP. Our ownership in DCP Midstream, LLC consists of Class A and Class B Interests which track to our investments in DCP, included in the Gas Transmission and Midstream segment, and Gray Oak, included in the Liquids Pipelines segment, respectively. Through our investment in DCP Midstream, LLC, we increased our effective economic interest in Gray Oak to 58.5% from 22.8% and reduced our effective economic interest in DCP to 13.2% from 28.3%. As a result of the transaction, Enbridge will assume operatorship of Gray Oak in the second quarter of 2023.

We determined the fair value of our decrease in economic interest in DCP based on the unadjusted quoted market price of DCP’s publicly traded common units on the transaction closing date. The fair value of our increased economic interest in Gray Oak was determined using the fair value prescribed to the change in our economic interest in DCP. As a result of the merger transaction and the realignment of our economic interests in DCP and Gray Oak, we also received cash consideration of approximately $522 million (US$404 million) and recorded an accounting gain of $1.1 billion (US$832 million) to Gain on joint venture merger transaction in the Consolidated Statements of Earnings. Both DCP and Gray Oak continue to be accounted for as equity method investments.

Woodfibre LNG Limited Partnership
On November 29, 2022, Enbridge acquired, for cash payment of $533 million (US$392 million), an effective 30.0% interest in Woodfibre. Woodfibre will operate a liquified natural gas export facility in BC being constructed by us and our partners.

Noverco Inc.
On June 7, 2021, IPL System Inc., a wholly-owned subsidiary of Enbridge, entered into a purchase and sale agreement to sell its 38.9% common share and preferred share interest in Noverco to Trencap L.P. On December 30, 2021, we closed the sale of Noverco for cash proceeds of $1.1 billion. After closing adjustments, a gain on disposal of $303 million before tax was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2021. Noverco was previously included in our Gas Distribution and Storage segment.

IMPAIRMENT OF EQUITY INVESTMENTS
PennEast Pipeline Company, LLC
PennEast Pipeline Company, LLC (PennEast) is a joint venture formed to develop a natural gas transmission pipeline to serve local distribution companies and power generators in southeastern Pennsylvania and New Jersey, is owned 20.0% by Enbridge, and is recorded as an equity method investment. In the third quarter of 2021, PennEast determined further development of the project was no longer viable and development of the project was ceased. As a result, we recorded an other-than-temporary impairment loss of $111 million on our investment for the year ended December 31, 2021 based on the estimated fair value of our share of the net assets. The carrying value of this investment as at December 31, 2022 and 2021 was nil and $12 million, respectively.

Steckman Ridge, LP
Steckman Ridge, LP (Steckman Ridge) is engaged in the storage of natural gas, is owned 50.0% by Enbridge, and is recorded as an equity method investment. During the year ended December 31, 2020, Steckman Ridge's forecasted performance was adjusted for the expectation that future available capacity will be re-contracted at lower than expected rates. As a result, we recorded an other-than-temporary impairment loss of $221 million on our investment for the year ended December 31, 2020 based on a discounted cash flow analysis. The carrying value of this investment as at December 31, 2022 and 2021 was $91 million and $88 million, respectively.

Southeast Supply Header, L.L.C.
Southeast Supply Header, L.L.C. (SESH) provides natural gas transmission services from east Texas and northern Louisiana to the southeast markets of the Gulf Coast, is owned 50.0% by Enbridge, and is recorded as an equity method investment. The forecasted performance of SESH was revised during the year ended December 31, 2020 to reflect downward revisions to future negotiated rates as well as higher than expected available capacity levels, caused primarily by a significant contract expiry. As a result, we recorded an other-than-temporary impairment loss of $394 million on our investment for the year ended December 31, 2020 based on a discounted cash flow analysis. The carrying value of this investment as at December 31, 2022 and 2021 was $86 million and $82 million, respectively.

DCP Midstream, LLC
DCP Midstream, LLC, an entity of which we had a 50.0% ownership interest in prior to the joint venture merger transaction with P66, holds an equity interest in DCP. A decline in the market price of DCP's publicly traded units during the first quarter of 2020 resulted in an other-than-temporary impairment loss on our investment in DCP Midstream, LLC of $1.7 billion for the year ended December 31, 2020. In addition, we incurred losses of $324 million through our equity earnings pick up in relation to asset and goodwill impairment losses recorded by DCP. The carrying value of our investment in DCP Midstream, LLC (Class A Units) as at December 31, 2022 and 2021 was $317 million and $397 million, respectively.

Our investments in PennEast, Steckman, SESH and DCP Midstream, LLC (Class A Units) form part of our Gas Transmission and Midstream segment. The impairment losses were recorded within Impairment of equity investments in the Consolidated Statements of Earnings.

14. RESTRICTED LONG-TERM INVESTMENTS

Effective January 1, 2015, we began collecting and setting aside funds to cover future pipeline abandonment costs for all CER regulated pipelines as a result of the CER's regulatory requirements under LMCI. The funds collected are held in trusts in accordance with the CER decision. The funds collected from shippers are reported within Transportation and other services revenues in the Consolidated Statements of Earnings and Restricted long-term investments in the Consolidated Statements of Financial Position. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense in the Consolidated Statements of Earnings and Other long-term liabilities in the Consolidated Statements of Financial Position.

We routinely invest excess cash and various restricted balances in securities such as commercial paper, bankers acceptances, corporate debt securities, Canadian equity securities, treasury bills and money market securities in the US and Canada.

As at December 31, 2022 and 2021, we had restricted long-term investments held in trust and classified as available-for-sale of $593 million and $630 million, respectively.

We had Restricted long-term investments held in trust totaling $236 million and $217 million as at December 31, 2022 and 2021, respectively, which are classified as Level 1 in the fair value hierarchy.
We also had Restricted long-term investments held in trust totaling $357 million (cost basis - $437 million) and $413 million (cost basis - $383 million) as at December 31, 2022 and 2021, respectively, which are classified as Level 2 in the fair value hierarchy. There were unrealized holding losses of $122 million and $8 million on our Restricted long-term investments for the years ended December 31, 2022 and 2021, respectively. Within Other long-term liabilities we had estimated future abandonment costs related to LMCI of $610 million and $649 million as at December 31, 2022 and 2021, respectively *(Note 7)*.

15. INTANGIBLE ASSETS

December 31, 2022	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	10.9 %	**2,019**	**(1,042)**	**977**
Power purchase agreements	4.2 %	**64**	**(23)**	**41**
Project agreement[1]	4.0 %	**163**	**(36)**	**127**
Customer relationships	8.6 %	**2,701**	**(459)**	**2,242**
Other intangible assets	5.9 %	**621**	**(148)**	**473**
Under development	— %	**158**	**—**	**158**
		5,726	**(1,708)**	**4,018**

December 31, 2021	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	12.0 %	2,067	(1,148)	919
Power purchase agreements	4.5 %	63	(21)	42
Project agreement[1]	4.0 %	152	(27)	125
Customer relationships	8.5 %	2,532	(215)	2,317
Other intangible assets	3.9 %	475	(116)	359
Under development	— %	246	—	246
		5,535	(1,527)	4,008

1 Represents a project agreement acquired from the merger of Enbridge and Spectra Energy.

For the years ended December 31, 2022, 2021 and 2020, our amortization expense related to intangible assets totaled $483 million, $348 million and $294 million, respectively. Our expected amortization expense associated with existing intangible assets for each of the years 2023 to 2027 is $498 million.

16. GOODWILL

	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Consolidated
(millions of Canadian dollars)						
Balance at January 1, 2021	7,828	19,480	5,378	—	2	32,688
Foreign exchange and other	(55)	(145)	—	—	—	(200)
Acquisition[3]	268	—	19	—	—	287
Balance at December 31, 2021[1,2]	8,041	19,335	5,397	—	2	32,775
Impairment	**—**	**(2,465)**	**—**	**—**	**—**	**(2,465)**
Foreign exchange and other	**506**	**1,236**	**—**	**(4)**	**—**	**1,738**
Acquisition[4]	**—**	**—**	**—**	**392**	**—**	**392**
Balance at December 31, 2022[1,2]	**8,547**	**18,106**	**5,397**	**388**	**2**	**32,440**

1 Gross goodwill as at December 31, 2022 and 2021 was $36.5 billion and $34.4 billion, respectively.
2 Accumulated impairment as at December 31, 2022 and 2021 was $4.1 billion and $1.6 billion, respectively.
3 In 2021 we recorded $268 million of goodwill related to the acquisition of Moda. Refer to Note 8 - Acquisitions and Dispositions.
4 In 2022, we recorded $392 million of goodwill related to the acquisition of TGE. Refer to Note 8 - Acquisitions and Dispositions.

IMPAIRMENT
Gas Transmission
During the year ended December 31, 2022, we recorded goodwill impairment of $2.5 billion related to our Gas Transmission reporting unit. The fair value of the reporting unit, determined using a combination of discounted cash flow and earnings multiples techniques, was impacted by a rise in cost of capital and lower projected long term growth rates for our existing assets.

17. ACCOUNTS PAYABLE AND OTHER

December 31,	**2022**	2021
(millions of Canadian dollars)		
Trade payables and operating accrued liabilities	**5,235**	4,470
Dividends payable	**1,825**	1,773
Current deferred credits	**1,056**	853
Construction payables and contractor holdbacks	**937**	844
Current derivative liabilities *(Note 24)*	**898**	717
Taxes payable	**683**	478
Other	**758**	632
	11,392	9,767

18. DEBT

December 31,	Weighted Average Interest Rate[9]	Maturity	**2022**	2021
(millions of Canadian dollars)				
Enbridge Inc.				
US dollar senior notes	3.5 %	2023 - 2051	**12,060**	10,992
Medium-term notes	3.8 %	2023 - 2064	**8,223**	8,123
Sustainability-linked bonds	2.0 %	2032 - 2033	**3,355**	2,363
Fixed-to-fixed subordinated term notes[1]	4.1 %	2080 - 2083	**3,596**	1,263
Fixed-to-floating rate subordinated term notes[2]	5.9 %	2077 - 2078	**6,736**	6,442
Floating rate notes[3]		2023 - 2024	**1,491**	1,579
Commercial paper and credit facility draws	4.8 %	2023 - 2027	**7,984**	7,837
Other[4]			**15**	5
Enbridge (U.S.) Inc.				
Commercial paper and credit facility draws	4.5 %	2024 - 2027	**4,199**	4,845
Other[4]			**7**	7
Enbridge Energy Partners, L.P.				
Senior notes	6.5 %	2025 - 2045	**3,320**	3,095
Enbridge Gas Inc.				
Medium-term notes	4.1 %	2023 - 2052	**9,535**	9,010
Debentures	9.1 %	2024 - 2025	**210**	210
Commercial paper and credit facility draws	4.5 %	2024	**2,000**	1,515
Other[4]			**1**	—
Enbridge Pipelines (Southern Lights) L.L.C.				
Senior notes	4.0 %	2040	**921**	949
Enbridge Pipelines Inc.				
Medium-term notes[5]	4.2 %	2023 - 2051	**5,425**	5,575
Debentures	8.2 %	2024	**200**	200
Commercial paper and credit facility draws	4.6 %	2024	**312**	667
Enbridge Southern Lights LP				
Senior notes	4.0 %	2040	**222**	240
Spectra Energy Capital, LLC				
Senior notes	7.0 %	2032 - 2038	**234**	218
Algonquin Gas Transmission, LLC				
Senior notes	3.3 %	2024 - 2029	**1,152**	1,074
East Tennessee Natural Gas, LLC				
Senior notes	3.1 %	2024	**258**	240
Texas Eastern Transmission, LP				
Senior notes	3.3 %	2028 - 2048	**3,455**	3,095
Spectra Energy Partners, LP				
Senior notes	4.3 %	2024 - 2045	**4,336**	4,042
Tri Global Energy, LLC				
Senior notes	12.7 %	2024	**18**	—
Westcoast Energy Inc.				
Medium-term notes	4.9 %	2024 - 2041	**1,225**	1,475
Debentures	8.1 %	2025 - 2026	**275**	275
Fair value adjustment			**608**	667
Other[6]			**(393)**	(363)
Total debt[7]			**80,980**	75,640
Current maturities			**(6,045)**	(6,164)
Short-term borrowings[8]			**(1,996)**	(1,515)
Long-term debt			**72,939**	67,961

1 For an initial five or 10 years, the notes carry a fixed interest rate. Subsequently, during each reset period the interest rate will be reset to equal to the Five-Year US Treasury rate or Five-Year Government of Canada bond yield plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.

2 For an initial five or 10 years, the notes carry a fixed interest rate. Subsequently, the interest rate will be floating and set to equal to the Canadian Dollar Offered Rate or the London Interbank Offered Rate (LIBOR) plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.

3 The notes carry an interest rate equal to Secured Overnight Financing Rate (SOFR) plus a margin of 40 basis points and SOFR plus a margin of 63 basis points.

4 Primarily finance lease obligations.

5 Included in medium-term notes is $100 million with a maturity date of 2112.

6 Primarily unamortized discounts, premiums and debt issuance costs.

7 2022 - $38 billion and US$31 billion; 2021 - $36 billion and US$31 billion. Totals exclude capital lease obligations, unamortized discounts, premiums and debt issuance costs and fair value adjustment.

8 Weighted average interest rates on outstanding commercial paper were 4.5% as at December 31, 2022 (2021 - 0.5%).

9 Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2022.

As at December 31, 2022, all outstanding debt was unsecured.

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at December 31, 2022:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2023-2027	**10,987**	**7,984**	**3,003**
Enbridge (U.S.) Inc.	2024-2027	**8,604**	**4,199**	**4,405**
Enbridge Pipelines Inc.	2024	**2,000**	**312**	**1,688**
Enbridge Gas Inc.	2024	**2,000**	**2,000**	**—**
Total committed credit facilities		**23,591**	**14,495**	**9,096**

1 Maturity date is inclusive of the one-year term out option for certain credit facilities.
2 Includes facility draws and commercial paper issuances that are back-stopped by credit facilities.

On February 10, 2022, we renewed our three year $1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

On May 17, 2022, we entered into a three year term loan with a syndicate of Japanese banks for approximately $806 million (¥84.8 billion), which will mature in May 2025 and replaces the approximately $499 million (¥52.5 billion) term loan that matured in May 2022. Additionally, on May 24, 2022, we entered into a 364-day term loan for approximately $1.9 billion, which will mature in May 2023.

On June 23, 2022, we renewed approximately $5.5 billion of our 364-day extendible credit facilities to July 2024, which includes a one-year term out provision from July 2023.

In July and August 2022, we renewed $12.7 billion of our credit facilities, extending the maturity dates of our 364-day credit facilities to July 2024, inclusive of a one year term out provision from July 2023, and our five year facilities out to July 2027. As a part of the renewals, we increased our credit facilities by approximately $640 million.

On December 16, 2022, Enbridge (U.S.) Inc. entered into a five year delay draw term loan in support of solar self-power projects for approximately $479 million, which will mature in December 2027.

In addition to the committed credit facilities noted above, we maintain $1.3 billion of uncommitted demand letter of credit facilities, of which $689 million was unutilized as at December 31, 2022. As at December 31, 2021, we had $1.3 billion of uncommitted demand letter of credit facilities, of which $854 million was unutilized.

Our credit facilities carry a weighted average standby fee of 0.1% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and we have the option to extend such facilities, which are currently scheduled to mature from 2023 to 2027.

As at December 31, 2022 and 2021, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $10.5 billion and $11.3 billion, respectively, were supported by the availability of long-term committed credit facilities and, therefore, have been classified as long-term debt.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2022, we completed the following long-term debt issuances totaling US$3.2 billion and $3.4 billion:

Company	Issue Date			Principal Amount
(millions of Canadian dollars unless otherwise stated)				
Enbridge Inc.				
	January 2022	5.00%	fixed-to-fixed subordinated notes due January 2082[1]	$750
	February 2022	Floating rate senior notes due February 2024[2]		US$600
	February 2022	2.15%	senior notes due February 2024	US$400
	February 2022	2.50%	senior notes due February 2025	US$500
	September 2022	7.38%	fixed-to-fixed subordinated notes due January 2083[3]	US$500
	September 2022	7.63%	fixed-to-fixed subordinated notes due January 2083[4]	US$600
	November 2022	5.70%	medium-term notes due November 2027	$600
	November 2022	6.10%	sustainability-linked medium-term notes due November 2032[5]	$900
	November 2022	6.51%	medium-term notes due November 2052	$500
Enbridge Gas Inc.				
	August 2022	4.15%	medium-term notes due August 2032	$325
	August 2022	4.55%	medium-term notes due August 2052	$325
Texas Eastern Transmission LP				
	December 2022	6.20%	senior notes due December 2032	US$600

1 For the initial 10 years, the notes carry a fixed interest rate. At year 10, the interest rate will be reset to equal to the Five-Year Government of Canada bond yield plus a margin of 3.54%. Subsequent to year 10, every five years, the Five-Year Government of Canada bond yield is reset. At year 30, the interest rate will be reset to equal to the Five-Year Government of Canada bond yield plus a margin of 4.29%.

2 Notes carry an interest rate set to equal the SOFR plus a margin of 63 basis points.

3 For the initial five years, the notes carry a fixed interest rate. At year five, the interest rate will be set to equal to the Five-Year US Treasury rate plus a margin of 3.71%. At year 10, the interest rate will be reset to equal the Five-Year US Treasury rate plus a margin of 3.96%. Subsequent to year 10, every five years, the Five-Year US Treasury rate is reset. At year 25, the interest rate will be reset to equal to the Five-Year US Treasury rate plus a margin of 4.71%.

4 For the initial 10 years, the notes carry a fixed interest rate. At year 10, the interest rate will be reset to equal to the Five-Year US Treasury rate plus a margin of 4.42%. Subsequent to year 10, every five years, the Five-Year US Treasury rate will be reset. At year 30, the interest rate will be reset to equal to the Five-Year US Treasury rate plus a margin of 5.17%.

5 The sustainability-linked medium-term notes are subject to a sustainability performance target of 35% reduction in emissions intensity at an observation date of December 31, 2030. If the target is not met, on November 9, 2031, the interest rate will be set to equal 6.10% plus a margin of 70 basis points.

LONG-TERM DEBT REPAYMENTS

During the year ended December 31, 2022, we completed the following long-term debt repayments totaling $1.5 billion and US$2.0 billion, respectively:

Company	Repayment Date			Principal Amount
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Inc.				
	February 2022	Floating rate notes[1]		US$750
	February 2022	4.85%	medium-term notes	$200
	July 2022	2.90%	senior notes	US$700
	December 2022	3.19%	medium-term notes	$350
	December 2022	3.19%	medium-term notes	$450
Enbridge Gas Inc.				
	April 2022	4.85%	medium-term notes	$125
Enbridge Pipelines (Southern Lights) L.L.C.				
	June and December 2022	3.98%	senior notes	US$72
Enbridge Pipelines Inc.				
	November 2022	2.93%	medium-term notes	$150
Enbridge Southern Lights LP				
	June and December 2022	4.01%	senior notes	$18
Texas Eastern Transmission, LP				
	October 2022	2.80%	senior notes	US$500
Westcoast Energy Inc.				
	December 2022	3.12%	medium-term notes	$250

1 Notes carried an interest rate set to equal the Three-Month LIBOR plus a margin of 50 basis points.

DEBT COVENANTS

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2022, we were in compliance with all debt covenants.

INTEREST EXPENSE

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Debentures and term notes	**2,910**	2,806	2,873
Commercial paper and credit facility draws	**388**	114	163
Amortization of fair value adjustment	**(45)**	(50)	(54)
Capitalized interest	**(74)**	(215)	(192)
	3,179	2,655	2,790

19. ASSET RETIREMENT OBLIGATIONS

Our ARO relate mostly to the retirement of pipelines, renewable power generation assets and obligations related to right-of way agreements and contractual leases for land use.

The discount rates used to estimate the present value of the expected future cash flows for the year ended December 31, 2022 ranged from 1.5% to 9.0% (2021 - 0.9% to 9.0%).

A reconciliation of movements in our ARO liabilities is as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Obligations at beginning of year	**502**	496
Liabilities incurred	**30**	—
Liabilities settled	**(126)**	(67)
Change in estimate and other	**51**	70
Foreign currency translation adjustment	**24**	(3)
Accretion expense	**7**	6
Obligations at end of year	**488**	502
Presented as follows:		
Accounts payable and other	**83**	160
Other long-term liabilities	**405**	342
	488	502

20. NONCONTROLLING INTERESTS

The following table provides additional information regarding Noncontrolling interests as presented in our Consolidated Statements of Financial Position:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Algonquin Gas Transmission, LLC	**400**	377
Enbridge Athabasca Midstream Investor Limited Partnership[1]	**1,106**	—
Maritimes & Northeast Pipeline, L.L.C.	**582**	546
Renewable energy assets	**1,302**	1,503
Westcoast Energy Inc.[2]	**117**	116
Other	**4**	—
	3,511	2,542

1 *On October 5, 2022, we closed the sale of an 11.6% non-operating interest in certain assets from our Regional Oil Sands System to Aii. Refer to* Note 8 - Acquisitions and Dispositions.
2 *During 2021, Westcoast Energy Inc. redeemed all of its remaining Cumulative Five-Year Minimum Rate Reset Redeemable First Preferred Shares.*

21. SHARE CAPITAL

Our authorized share capital consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

	2022		2021		2020	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)						
Balance at beginning of year	**2,026**	**64,799**	2,026	64,768	2,025	64,746
Shares issued on exercise of stock options	**2**	**53**	—	31	1	22
Share purchases at stated value[1]	**(3)**	**(88)**	—	—	—	—
Other	**—**	**(4)**	—	—	—	—
Balance at end of year	**2,025**	**64,760**	2,026	64,799	2,026	64,768

1 *Reflects the repurchase and cancellation of common shares under our normal course issuer bid.*

PREFERENCE SHARES

	2022		2021		2020	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)						
Preference Shares, Series A	**5**	**125**	5	125	5	125
Preference Shares, Series B	**20**	**500**	18	457	18	457
Preference Shares, Series C[1]	**—**	**—**	2	43	2	43
Preference Shares, Series D	**18**	**450**	18	450	18	450
Preference Shares, Series F	**20**	**500**	20	500	20	500
Preference Shares, Series H	**14**	**350**	14	350	14	350
Preference Shares, Series J[2]	**—**	**—**	8	199	8	199
Preference Shares, Series L	**16**	**411**	16	411	16	411
Preference Shares, Series N	**18**	**450**	18	450	18	450
Preference Shares, Series P	**16**	**400**	16	400	16	400
Preference Shares, Series R	**16**	**400**	16	400	16	400
Preference Shares, Series 1	**16**	**411**	16	411	16	411
Preference Shares, Series 3	**24**	**600**	24	600	24	600
Preference Shares, Series 5	**8**	**206**	8	206	8	206
Preference Shares, Series 7	**10**	**250**	10	250	10	250
Preference Shares, Series 9	**11**	**275**	11	275	11	275
Preference Shares, Series 11	**20**	**500**	20	500	20	500
Preference Shares, Series 13	**14**	**350**	14	350	14	350
Preference Shares, Series 15	**11**	**275**	11	275	11	275
Preference Shares, Series 17[3]	**—**	**—**	30	750	30	750
Preference Shares, Series 19	**20**	**500**	20	500	20	500
Issuance costs		**(135)**		(155)		(155)
Balance at end of year		**6,818**		7,747		7,747

1 On June 1, 2022, all outstanding Preference Shares, Series C were converted to Preference Shares, Series B.
2 On June 1, 2022, we redeemed our US$200 million outstanding Cumulative Redeemable Preference Shares, Series J.
3 On March 1, 2022, we redeemed our $750 million outstanding Cumulative Redeemable Minimum Rate Reset Preference Shares, Series 17.

Characteristics of our outstanding preference shares are as follows:

	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars unless otherwise stated)					
Preference Shares, Series A	5.50 %	$1.37500	$25	—	—
Preference Shares, Series B[5]	5.20 %	$1.30052	$25	June 1, 2027	Series C
Preference Shares, Series D	4.46 %	$1.11500	$25	March 1, 2023	Series E
Preference Shares, Series F	4.69 %	$1.17224	$25	June 1, 2023	Series G
Preference Shares, Series H	4.38 %	$1.09400	$25	September 1, 2023	Series I
Preference Shares, Series L[6]	5.86 %	US$1.46448	US$25	September 1, 2027	Series M
Preference Shares, Series N	5.09 %	$1.27152	$25	December 1, 2023	Series O
Preference Shares, Series P	4.38 %	$1.09476	$25	March 1, 2024	Series Q
Preference Shares, Series R	4.07 %	$1.01825	$25	June 1, 2024	Series S
Preference Shares, Series 1	5.95 %	US$1.48728	US$25	June 1, 2023	Series 2
Preference Shares, Series 3	3.74 %	$0.93425	$25	September 1, 2024	Series 4
Preference Shares, Series 5	5.38 %	US$1.34383	US$25	March 1, 2024	Series 6
Preference Shares, Series 7	4.45 %	$1.11224	$25	March 1, 2024	Series 8
Preference Shares, Series 9	4.10 %	$1.02424	$25	December 1, 2024	Series 10
Preference Shares, Series 11	3.94 %	$0.98452	$25	March 1, 2025	Series 12
Preference Shares, Series 13	3.04 %	$0.76076	$25	June 1, 2025	Series 14
Preference Shares, Series 15	2.98 %	$0.74576	$25	September 1, 2025	Series 16
Preference Shares, Series 19	4.90 %	$1.22500	$25	March 1, 2023	Series 20

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board of Directors. With the exception of Preference Shares, Series A, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Preference Shares, Series 19 contain a feature where the fixed dividend rate, when reset every five years, will not be less than 4.90%. No other series of Preference Shares has this feature.*

2 *Preference Shares, Series A may be redeemed any time at our option. For all other series of preference shares, we may at our option, redeem all or a portion of the outstanding preference shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.*

4 *With the exception of Preference Shares, Series A, after the redemption and conversion option dates, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/number of days in year) x Three-Month Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), or 3.2% (Series 20); or US$25 x (number of days in quarter/number of days in year) x Three-Month US Government treasury bill rate + 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).*

5 *The quarterly dividend per share paid on Preference Shares, Series B was increased to $0.32513 from $0.21340 on June 1, 2022 due to reset of the annual dividend on June 1, 2022. On June 1, 2022, all outstanding Preference Shares, Series C were converted to Preference Shares, Series B.*

6 *The quarterly dividend per share paid on Preference Shares, Series L was increased to US$0.36612 from US$0.30993 on September 1, 2022, due to reset of the annual dividend on September 1, 2022.*

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of our shareholders in connection with any takeover offer. Rights issued under the plan become exercisable when a person and any related parties acquires or announces its intention to acquire 20% or more of our outstanding common shares without complying with certain provisions set out in the plan or without approval of our Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase our common shares at a 50% discount to the market price at that time.

22. STOCK OPTION AND STOCK UNIT PLANS

We maintain three long-term incentive compensation plans: the ISO Plan, the PSU Plan and the RSU Plan. Total stock-based compensation expense recorded for the years ended December 31, 2022, 2021 and 2020 was $260 million, $157 million and $145 million, respectively. Disclosure of activity and assumptions for material stock-based compensation plans are included below.

INCENTIVE STOCK OPTIONS

Certain key employees are granted ISOs to purchase common shares at the grant date market price. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2022	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; weighted average exercise price in Canadian dollars; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**34,017**	**49.28**		
Options granted	**3,430**	**49.58**		
Options exercised[1]	**(8,684)**	**44.55**		
Options cancelled or expired	**(1,139)**	**51.32**		
Options outstanding at end of year	**27,624**	**48.46**	**5.7**	**133**
Options vested at end of year[2]	**17,631**	**49.20**	**4.4**	**84**

1 The total intrinsic value of ISOs exercised during the years ended December 31, 2022, 2021 and 2020 was $66 million, $24 million and $13 million, respectively, and cash received on exercise was $3 million, $2 million and $4 million, respectively.
2 The total fair value of ISOs exercised during the years ended December 31, 2022, 2021 and 2020 was $21 million, $25 million and $30 million, respectively.

Weighted average assumptions used to determine the fair value of ISOs granted using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2022**	2021	2020
Fair value per option *(Canadian dollars)*[1]	**5.07**	4.10	4.01
Valuation assumptions			
Expected option term *(years)*[2]	**6**	6	6
Expected volatility[3]	**21.9 %**	25.5 %	18.3 %
Expected dividend yield[4]	**6.5 %**	7.6 %	5.9 %
Risk-free interest rate[5]	**1.8 %**	0.7 %	1.3 %

1 Options granted to US employees are based on the New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the US and the Canadian options. The fair values per option for the years ended December 31, 2022, 2021 and 2020 were $4.78, $3.91 and $3.75, respectively, for Canadian employees and US$4.62, US$3.65 and US$3.62, respectively, for US employees.
2 The expected option term is six years based on historical exercise practice and five years for retirement eligible employees.
3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.
4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.
5 The risk-free interest rate is based on the Government of Canada's Canadian bond yields and the US Treasury bond yields.

Compensation expense recorded for the years ended December 31, 2022, 2021 and 2020 for ISOs was $15 million, $16 million and $24 million, respectively. As at December 31, 2022, unrecognized compensation expense related to non-vested stock-based compensation arrangements granted under the ISO Plan was $12 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE STOCK UNITS

Under PSU awards for certain key employees, cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if our performance fails to meet threshold performance levels, to a maximum of 2.0 if we perform within the highest range of the performance targets. The performance multiplier is derived through a calculation of our Total Shareholder Return percentile rank, in each case relative to a specified peer group of companies and our distributable cash flow per share, adjusted for unusual, infrequent or other non-operating factors, relative to targets established at the time of grant. To calculate the 2022 expense, a multiplier of 1.25 was used for 2022 PSU grants, 1.25 for 2021 PSU grants and 2.00 for the 2020 PSU grants.

December 31, 2022	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**3,429**		
Units granted	**1,467**		
Units cancelled	**(131)**		
Units matured[1]	**(1,700)**		
Dividend reinvestment	**184**		
Units outstanding at end of year	**3,249**	**1.1**	**261**

1 The total amount paid during the years ended December 31, 2022, 2021 and 2020 for PSUs was $90 million, $70 million and $14 million, respectively.

Compensation expense recorded for the years ended December 31, 2022, 2021 and 2020 for PSUs was $169 million, $56 million and $76 million, respectively. As at December 31, 2022, unrecognized compensation expense related to non-vested PSUs was $72 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Under RSU awards, cash awards are paid to certain of our employees vesting in equal installments on each of the first, second and third anniversaries of the grant date. Share-settled awards are given to certain senior management employees following a three year maturity period. RSU holders receive shares or cash equal to our weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2022	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**2,705**		
Units granted	**1,400**		
Units cancelled	**(134)**		
Units matured[1]	**(602)**		
Dividend reinvestment	**196**		
Units outstanding at end of year	**3,565**	**1.0**	**185**

1 The total amount paid during the years ended December 31, 2022, 2021 and 2020 for RSUs was $32 million, $72 million and $27 million, respectively.

Compensation expense recorded for the years ended December 31, 2022, 2021 and 2020 for RSUs was $76 million, $85 million and $44 million, respectively. As at December 31, 2022, unrecognized compensation expense related to non-vested RSUs was $35 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

23. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

Changes in AOCI attributable to our common shareholders for the years ended December 31, 2022, 2021 and 2020 are as follows:

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2022	**(897)**	**—**	**(166)**	**56**	**(5)**	**(84)**	**(1,096)**
Other comprehensive income/(loss) retained in AOCI	**1,125**	**(35)**	**(971)**	**4,292**	**(6)**	**411**	**4,816**
Other comprehensive loss/(income) reclassified to earnings							
Interest rate contracts[1]	**186**	**—**	**—**	**—**	**—**	**—**	**186**
Foreign exchange contracts[2]	**(4)**	**—**	**—**	**—**	**—**	**—**	**(4)**
Other contracts[3]	**4**	**—**	**—**	**—**	**—**	**—**	**4**
Amortization of pension and OPEB actuarial gain[4]	**—**	**—**	**—**	**—**	**—**	**(14)**	**(14)**
Other	**—**	**—**	**—**	**—**	**16**	**—**	**16**
	1,311	**(35)**	**(971)**	**4,292**	**10**	**397**	**5,004**
Tax impact							
Income tax on amounts retained in AOCI	**(250)**	**—**	**—**	**—**	**—**	**(99)**	**(349)**
Income tax on amounts reclassified to earnings	**(43)**	**—**	**—**	**—**	**—**	**4**	**(39)**
	(293)	**—**	**—**	**—**	**—**	**(95)**	**(388)**
Balance as at December 31, 2022	**121**	**(35)**	**(1,137)**	**4,348**	**5**	**218**	**3,520**

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2021	(1,326)	5	(215)	568	66	(499)	(1,401)
Other comprehensive income/(loss) retained in AOCI	238	(5)	49	(492)	(12)	520	298
Other comprehensive loss/(income) reclassified to earnings							
Interest rate contracts[1]	296	—	—	—	—	—	296
Commodity contracts[5]	1	—	—	—	—	—	1
Foreign exchange contracts[2]	5	—	—	—	—	—	5
Other contracts[3]	2	—	—	—	—	—	2
Equity investment disposal	—	—	—	—	(66)	—	(66)
Amortization of pension and OPEB actuarial loss and prior service costs[4]	—	—	—	—	—	28	28
Other	17	—	—	(20)	3	—	—
	559	(5)	49	(512)	(75)	548	564
Tax impact							
Income tax on amounts retained in AOCI	(61)	—	—	—	—	(126)	(187)
Income tax on amounts reclassified to earnings	(69)	—	—	—	4	(7)	(72)
	(130)	—	—	—	4	(133)	(259)
Balance as at December 31, 2021	(897)	—	(166)	56	(5)	(84)	(1,096)

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2020	(1,073)	—	(317)	1,396	67	(345)	(272)
Other comprehensive income/(loss) retained in AOCI	(591)	5	115	(828)	(2)	(221)	(1,522)
Other comprehensive loss/(income) reclassified to earnings							
Interest rate contracts[1]	253	—	—	—	—	—	253
Foreign exchange contracts[2]	5	—	—	—	—	—	5
Other contracts[3]	(2)	—	—	—	—	—	(2)
Amortization of pension and OPEB actuarial loss and prior service costs[4]	—	—	—	—	—	17	17
	(335)	5	115	(828)	(2)	(204)	(1,249)
Tax impact							
Income tax on amounts retained in AOCI	140	—	(13)	—	1	54	182
Income tax on amounts reclassified to earnings	(58)	—	—	—	—	(4)	(62)
	82	—	(13)	—	1	50	120
Balance as at December 31, 2020	(1,326)	5	(215)	568	66	(499)	(1,401)

1 Reported within Interest expense in the Consolidated Statements of Earnings.
2 Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.
3 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.
4 These components are included in the computation of net periodic benefit (credit)/cost and are reported within Other income/(expense) in the Consolidated Statements of Earnings.
5 Reported within Transportation and other services revenues, Commodity sales, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

Our earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price (collectively, market risks). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

We generate certain revenues, incur expenses and hold a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

We employ financial derivative instruments to hedge foreign currency denominated earnings exposure. A combination of qualifying cash flow, fair value and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses and to manage variability in cash flows. We hedge certain net investments in US dollar-denominated investments and subsidiaries using foreign currency derivatives and US dollar-denominated debt.

Interest Rate Risk

Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% of floating rate debt as a percentage of total debt outstanding. We primarily use qualifying derivative instruments to manage interest rate risk. Pay fixed-receive floating interest rate swaps may be used to hedge against the effect of future interest rate movements. We have implemented a hedging program to partially mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps. These hedges have an average fixed rate of 4.0%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of changes in market interest rates. Pay floating-receive fixed interest rate swaps are used, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in fair value via execution of fixed to floating interest rate swaps. As at December 31, 2022, we do not have any pay floating-receive fixed interest rate swaps outstanding.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have established a program including some of our subsidiaries to partially mitigate our exposure to long-term interest rate variability on forecasted term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.2%.

Commodity Price Risk

Our earnings and cash flows are exposed to changes in commodity prices as a result of our ownership interests in certain assets and investments, as well as through the activities of our energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. We employ financial and physical derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use primarily non-qualifying derivative instruments to manage commodity price risk.

Equity Price Risk

Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. We use equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted share units. We use a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS

We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our financial derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit events and reduce our credit risk exposure on financial derivative asset positions outstanding with the counterparties in those circumstances.

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments, as well as the maximum potential settlement amounts in the event of the specific circumstances described above. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2022	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	**—**	**—**	**46**	**46**	**(41)**	**5**
Interest rate contracts	**649**	**—**	**11**	**660**	**—**	**660**
Commodity contracts	**—**	**—**	**302**	**302**	**(182)**	**120**
Other contracts	**—**	**—**	**7**	**7**	**—**	**7**
	649	**—**	**366**	**1,015**	**(223)**	**792**
Deferred amounts and other assets						
Foreign exchange contracts	**—**	**156**	**153**	**309**	**(138)**	**171**
Interest rate contracts	**254**	**—**	**—**	**254**	**—**	**254**
Commodity contracts	**—**	**—**	**61**	**61**	**(25)**	**36**
Other contracts	**1**	**—**	**2**	**3**	**—**	**3**
	255	**156**	**216**	**627**	**(163)**	**464**
Accounts payable and other						
Foreign exchange contracts	**—**	**(42)**	**(524)**	**(566)**	**41**	**(525)**
Commodity contracts	**(48)**	**—**	**(284)**	**(332)**	**182**	**(150)**
	(48)	**(42)**	**(808)**	**(898)**	**223**	**(675)**
Other long-term liabilities						
Foreign exchange contracts	**—**	**—**	**(1,116)**	**(1,116)**	**138**	**(978)**
Interest rate contracts	**(3)**	**—**	**(1)**	**(4)**	**—**	**(4)**
Commodity contracts	**(37)**	**—**	**(133)**	**(170)**	**25**	**(145)**
	(40)	**—**	**(1,250)**	**(1,290)**	**163**	**(1,127)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**—**	**114**	**(1,441)**	**(1,327)**	**—**	**(1,327)**
Interest rate contracts	**900**	**—**	**10**	**910**	**—**	**910**
Commodity contracts	**(85)**	**—**	**(54)**	**(139)**	**—**	**(139)**
Other contracts	**1**	**—**	**9**	**10**	**—**	**10**
	816	**114**	**(1,476)**	**(546)**	**—**	**(546)**

December 31, 2021	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	—	—	259	259	(41)	218
Interest rate contracts	64	—	—	64	—	64
Commodity contracts	—	—	204	204	(129)	75
Other contracts	—	—	2	2	—	2
	64	—	465	529	(170)	359
Deferred amounts and other assets						
Foreign exchange contracts	—	—	240	240	(61)	179
Interest rate contracts	88	—	—	88	(1)	87
Commodity contracts	—	—	29	29	(13)	16
Other contracts	—	—	3	3	—	3
	88	—	272	360	(75)	285
Accounts payable and other						
Foreign exchange contracts	(15)	(112)	(176)	(303)	41	(262)
Interest rate contracts	(150)	—	—	(150)	—	(150)
Commodity contracts	(14)	—	(250)	(264)	129	(135)
	(179)	(112)	(426)	(717)	170	(547)
Other long-term liabilities						
Foreign exchange contracts	—	—	(423)	(423)	61	(362)
Interest rate contracts	(1)	—	(23)	(24)	1	(23)
Commodity contracts	(17)	—	(67)	(84)	13	(71)
	(18)	—	(513)	(531)	75	(456)
Total net derivative asset/(liability)						
Foreign exchange contracts	(15)	(112)	(100)	(227)	—	(227)
Interest rate contracts	1	—	(23)	(22)	—	(22)
Commodity contracts	(31)	—	(84)	(115)	—	(115)
Other contracts	—	—	5	5	—	5
	(45)	(112)	(202)	(359)	—	(359)

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

	2022							2021
As at December 31,	2023	2024	2025	2026	2027	Thereafter	Total	Total
Foreign exchange contracts - US dollar forwards - purchase *(millions of US dollars)*	**655**	**1,000**	**500**	**—**	**—**	**—**	**2,155**	2,508
Foreign exchange contracts - US dollar forwards - sell *(millions of US dollars)*	**8,297**	**6,386**	**4,613**	**4,121**	**2,837**	**1,356**	**27,610**	25,427
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**29**	**30**	**30**	**28**	**32**	**—**	**149**	177
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**92**	**91**	**86**	**85**	**81**	**262**	**697**	801
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**—**	**—**	**84,800**	**—**	**—**	**—**	**84,800**	72,500
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**8,698**	**538**	**30**	**26**	**25**	**39**	**9,356**	597
Interest rate contracts - long-term pay fixed rate *(millions of Canadian dollars)*	**5,496**	**1,766**	**589**	**—**	**—**	**—**	**7,851**	5,279
Equity contracts *(millions of Canadian dollars)*	**37**	**31**	**12**	**—**	**—**	**—**	**80**	67
Commodity contracts - natural gas *(billions of cubic feet)*	**52**	**25**	**15**	**1**	**—**	**—**	**93**	199
Commodity contracts - crude oil *(millions of barrels)*	**16**	**—**	**—**	**—**	**—**	**—**	**16**	12
Commodity contracts - power *(megawatt per hour (MW/H))*	**26**	**(25)**	**(44)**	**—**	**—**	**—**	**(14)** [1]	(43) [1]

1 *Total is an average net purchase/(sell) of power.*

Fair Value Derivatives

For foreign exchange derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative is included in Other income/(expense) or Interest expense in the Consolidated Statements of Earnings. The offsetting loss or gain on the hedged item attributable to the hedged risk is included in Other income/(expense) in the Consolidated Statements of Earnings. Any excluded components are included in the Consolidated Statements of Comprehensive Income.

Year ended December 31,	2022	2021
(millions of Canadian dollars)		
Unrealized gain on derivative	**262**	8
Unrealized loss on hedged item	**(254)**	(15)
Realized loss on derivative	**(110)**	(41)
Realized gain on hedged item	**85**	45

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges and net investment hedges on our consolidated earnings and consolidated comprehensive income, before the effect of income taxes:

	2022	2021	2020
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**3**	(29)	(1)
Interest rate contracts	**1,151**	252	(595)
Commodity contracts	**(53)**	(28)	2
Other contracts	**(4)**	1	(3)
Fair value hedges			
Foreign exchange contracts	**(35)**	(5)	5
Net investment hedges			
Foreign exchange contracts	**—**	—	13
	1,062	191	(579)
Amount of (gain)/loss reclassified from AOCI to earnings			
Foreign exchange contracts[1]	**13**	5	5
Interest rate contracts[2]	**186**	296	253
Commodity contracts[3]	**—**	1	—
Other contracts[3]	**4**	2	(2)
	203	304	256

1 Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.
2 Reported within Interest expense in the Consolidated Statements of Earnings.
3 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

We estimate that a gain of $67 million from AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 36 months as at December 31, 2022.

Non-Qualifying Derivatives

The following table presents the unrealized gains and losses associated with changes in the fair value of our non-qualifying derivatives:

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**(1,344)**	92	902
Interest rate contracts[2]	**10**	2	(25)
Commodity contracts[3]	**50**	71	(114)
Other contracts[4]	**4**	8	(7)
Total unrealized derivative fair value gain/(loss), net	**(1,280)**	173	756

1 For the respective annual periods, reported within Transportation and other services revenue (2022 - $238 million loss; 2021 - $98 million gain; 2020 - $533 million gain) and Other income/(expense) (2022 - $1,106 million loss; 2021 - $6 million loss; 2020 - $369 million gain) in the Consolidated Statements of Earnings.
2 Reported as an increase within Interest expense in the Consolidated Statements of Earnings.
3 For the respective annual periods, reported within Transportation and other services revenue (2022 - $13 million gain; 2021 - $9 million gain; 2020 - $2 million loss), Commodity sales (2022 - $89 million gain; 2021 - $160 million gain; 2020 - $321 million loss), Commodity costs (2022 - $102 million loss; 2021 - $105 million loss; 2020 - $207 million gain) and Operating and administrative expense (2022 - $50 million gain; 2021 - $7 million gain; 2020 - $2 million gain) in the Consolidated Statements of Earnings.
4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. Our shelf prospectuses with securities regulators enable ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2022. As a result, all credit facilities are available to us and the banks are obligated to fund us under the terms of the facilities.

CREDIT RISK

Entering into derivative instruments may result in exposure to credit risk from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, we enter into risk management transactions primarily with institutions that possess strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through maintenance and monitoring of credit exposure limits and contractual requirements, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

We have credit concentrations and credit exposure, with respect to derivative instruments, in the following counterparty segments:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Canadian financial institutions	**644**	424
US financial institutions	**277**	130
European financial institutions	**334**	181
Asian financial institutions	**224**	30
Other[1]	**105**	122
	1,584	887

1 Other is comprised of commodity clearing house and physical natural gas and crude oil counterparties.

As at December 31, 2022, we did not provide any letters of credit in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant International Swaps and Derivatives Association agreements. We held no cash collateral on derivative asset exposures as at December 31, 2022 and December 31, 2021.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates, and are reflected at fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Within Enbridge Gas, credit risk is mitigated by the utility's large and diversified customer base and the ability to recover an estimate for expected credit losses through the ratemaking process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default on receivables. Generally, we utilize a loss allowance matrix which contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations to measure lifetime expected credit losses of receivables. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimates of market value based on generally accepted valuation techniques or models and is supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our financial instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes financial instruments measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a financial instrument is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations, US and Canadian treasury bills, investments in exchange-traded equity funds held by our captive insurance subsidiaries, as well as restricted long-term investments in Canadian equity securities that are held in trust in accordance with the CER's regulatory requirements under the LMCI.

Level 2

Level 2 includes financial instrument valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Financial instruments in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the financial instrument. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps and options for which observable inputs can be obtained.

We have also categorized the fair value of our long-term debt, investments in debt securities held by our captive insurance subsidiaries, and restricted long-term investments in Canadian government bonds held in accordance with the CER's regulatory requirements under the LMCI as Level 2. The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor. When possible, the fair value of our restricted long-term investments is based on quoted market prices for similar instruments and, if not available, based on broker quotes.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power, NGL and natural gas contracts, basis swaps, commodity swaps, and power and energy swaps, as well as physical forward commodity contracts. We do not have any other financial instruments categorized in Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, we use observable market prices (interest, foreign exchange, commodity and share price) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread as well as the credit default swap spreads associated with our counterparties in our estimation of fair value.

We have categorized our derivative assets and liabilities measured at fair value as follows:

December 31, 2022	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**46**	**—**	**46**
Interest rate contracts	**—**	**660**	**—**	**660**
Commodity contracts	**65**	**90**	**147**	**302**
Other contracts	**—**	**7**	**—**	**7**
	65	**803**	**147**	**1,015**
Long-term derivative assets				
Foreign exchange contracts	**—**	**309**	**—**	**309**
Interest rate contracts	**—**	**254**	**—**	**254**
Commodity contracts	**—**	**17**	**44**	**61**
Other contracts	**—**	**3**	**—**	**3**
	—	**583**	**44**	**627**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(566)**	**—**	**(566)**
Commodity contracts	**(60)**	**(77)**	**(195)**	**(332)**
	(60)	**(643)**	**(195)**	**(898)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(1,116)**	**—**	**(1,116)**
Interest rate contracts	**—**	**(4)**	**—**	**(4)**
Commodity contracts	**—**	**(38)**	**(132)**	**(170)**
	—	**(1,158)**	**(132)**	**(1,290)**
Total net financial asset/(liability)				
Foreign exchange contracts	**—**	**(1,327)**	**—**	**(1,327)**
Interest rate contracts	**—**	**910**	**—**	**910**
Commodity contracts	**5**	**(8)**	**(136)**	**(139)**
Other contracts	**—**	**10**	**—**	**10**
	5	**(415)**	**(136)**	**(546)**

December 31, 2021	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	259	—	259
Interest rate contracts	—	64	—	64
Commodity contracts	38	71	95	204
Other contracts	—	2	—	2
	38	396	95	529
Long-term derivative assets				
Foreign exchange contracts	—	240	—	240
Interest rate contracts	—	88	—	88
Commodity contracts	—	21	8	29
Other contracts	—	3	—	3
	—	352	8	360
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(303)	—	(303)
Interest rate contracts	—	(150)	—	(150)
Commodity contracts	(52)	(66)	(146)	(264)
	(52)	(519)	(146)	(717)
Long-term derivative liabilities				
Foreign exchange contracts	—	(423)	—	(423)
Interest rate contracts	—	(24)	—	(24)
Commodity contracts	—	(19)	(65)	(84)
	—	(466)	(65)	(531)
Total net financial asset/(liability)				
Foreign exchange contracts	—	(227)	—	(227)
Interest rate contracts	—	(22)	—	(22)
Commodity contracts	(14)	7	(108)	(115)
Other contracts	—	5	—	5
	(14)	(237)	(108)	(359)

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

December 31, 2022	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**(35)**	**Forward gas price**	**4.57**	**34.56**	**6.25**	**$/mmbtu[2]**
Crude	**(4)**	**Forward crude price**	**71.10**	**105.22**	**83.26**	**$/barrel**
Power	**(71)**	**Forward power price**	**36.63**	**364.00**	**103.30**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(41)**	**Forward gas price**	**1.67**	**33.89**	**6.00**	**$/mmbtu[2]**
Crude	**(2)**	**Forward crude price**	**64.43**	**116.60**	**86.25**	**$/barrel**
Power	**17**	**Forward power price**	**30.49**	**183.88**	**72.48**	**$/MW/H**
	(136)					

1 Financial and physical forward commodity contracts are valued using a market approach valuation technique.
2 One million British thermal units (mmbtu).

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of our Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives.

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(108)**	(191)
Total gain/(loss)		
Included in earnings[1]	**6**	(39)
Included in OCI	**(54)**	(29)
Settlements	**20**	151
Level 3 net derivative liability at end of period	**(136)**	(108)

1 Reported within Transportation and other services revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

There were no transfers into or out of Level 3 as at December 31, 2022 or 2021.

NET INVESTMENT HEDGES

We currently have designated a portion of our US dollar-denominated debt as a hedge of our net investment in US dollar-denominated investments and subsidiaries.

During the years ended December 31, 2022 and 2021, we recognized an unrealized foreign exchange loss of $954 million and gain of $49 million, respectively, on the translation of US dollar-denominated debt, in OCI. No unrealized gains or losses on the change in fair value of our outstanding foreign exchange forward contracts were recognized in OCI during the years ended December 31, 2022 and 2021. No realized gains or losses associated with the settlement of foreign exchange forward contracts were recognized in OCI during the years ended December 31, 2022 and 2021. During the years ended December 31, 2022 and 2021, we recognized a realized loss of $21 million and nil, respectively, associated with the settlement of US dollar-denominated debt that had matured during the period, in OCI.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

Certain long-term investments in other entities with no actively quoted prices are classified as FVMA investments and are recorded at cost less impairment. The carrying value of FVMA investments totaled $102 million and $52 million as at December 31, 2022 and 2021, respectively.

As at December 31, 2022, the fair value of short- and long-term investments in equity funds and debt securities held by our captive insurance subsidiaries was $145 million and $488 million, respectively (2021 - $14 million and $290 million, respectively). These investments in equity funds and debt securities are recognized at fair value, classified as Level 1 and Level 2 in the fair value hierarchy, and are recorded in Accounts receivable and other and Long-term investments, respectively, in the Consolidated Statements of Financial Position. There were unrealized holding losses in equity funds and debt securities of $26 million for the year ended December 31, 2022 (2021 - losses of $12 million).

As at December 31, 2022 and 2021, our long-term debt had a carrying value of $79.3 billion and $74.4 billion, respectively, before debt issuance costs and a fair value of $73.5 billion and $82.0 billion, respectively. We also have non-current notes receivable carried at book value and recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at December 31, 2022 and 2021, the non-current notes receivable had a carrying value of $752 million and $954 million, respectively, which also approximates their fair value.

The fair value of financial assets and liabilities other than derivative instruments, long-term investments, restricted long-term investments, long-term debt and non-current notes receivable described above approximate their carrying value due to the short period to maturity.

25. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before income taxes	**4,542**	7,729	4,190
Canadian federal statutory income tax rate	**15 %**	15 %	15 %
Expected federal taxes at statutory rate	**681**	1,159	629
Increase/(decrease) resulting from:			
Provincial and state income taxes[1]	**108**	228	288
Foreign and other statutory rate differentials[2]	**295**	134	(53)
Effects of rate-regulated accounting[3]	**(122)**	(139)	(145)
Foreign allowable interest deductions	**—**	—	(4)
Part VI.1 tax, net of federal Part I deduction[4]	**76**	73	76
US Minimum Tax[5]	**107**	—	44
Non-taxable portion of gain on sale of investment[6]	**—**	(23)	—
Valuation allowance	**6**	5	(6)
Accounting impairment of non-deductible goodwill[7]	**370**	—	—
Noncontrolling interests[8]	**9**	(17)	(8)
Other[9]	**74**	(5)	(47)
Income tax expense	**1,604**	1,415	774
Effective income tax rate	**35.3 %**	18.3 %	18.5 %

1 *The change in provincial and state income taxes from 2021 to 2022 reflects the decrease in earnings from Canadian operations and the effect of the reduction in the Pennsylvania corporate income tax rate in the US, partially offset by the increase in earnings from US operations before the non-deductible goodwill impairment relating to the Gas Transmission reporting unit in combination with state tax apportionment changes. Refer to* Note 16 - Goodwill.
2 *The change in foreign and other statutory rate differentials from 2021 to 2022 reflects the increase in earnings from US operations, before the goodwill impairment relating to the Gas Transmission reporting unit. Refer to* Note 16 - Goodwill.
3 *The amount in 2022 relates to the federal component of the tax impact relating to the 2022 variable consideration attributable to the Canadian Mainline. Refer to* Note 4 - Revenue.
4 *Part VI.1 tax is a tax levied on preferred share dividends paid in Canada.*
5 *There was no US Minimum Tax in 2021 as a result of tax losses from bonus tax depreciation.*
6 *The amount in 2021 relates to the federal impact of the gain on sale of the investment in Noverco.*
7 *The amount in 2022 relates to the federal impact of the non-deductible goodwill impairment relating to the Gas Transmission reporting unit. Refer to* Note 16 - Goodwill.
8 *The amount in 2022 includes the federal tax impact of an impairment to Magic Valley attributable to noncontrolling interests. Refer to* Note 11 - Property, Plant and Equipment.
9 *The amount in 2022 includes the federal component of the tax impact relating to the 2021 variable consideration attributable to the Canadian Mainline. Refer to* Note 4 - Revenue.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**583**	3,399	2,789
US	**2,865**	3,336	407
Other	**1,094**	994	994
	4,542	7,729	4,190
Current income taxes			
Canada	**360**	162	165
US	**201**	80	64
Other	**86**	82	98
	647	324	327
Deferred income taxes			
Canada	**(358)**	344	378
US	**1,309**	741	66
Other	**6**	6	3
	957	1,091	447
Income tax expense	**1,604**	1,415	774

COMPONENTS OF DEFERRED INCOME TAXES

Deferred income tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(9,096)**	(8,721)
Investments	**(7,099)**	(6,097)
Regulatory assets	**(1,291)**	(1,245)
Pension and OPEB plans	**(30)**	—
Other	**(46)**	(208)
Total deferred income tax liabilities	**(17,562)**	(16,271)
Deferred income tax assets		
Financial instruments	**456**	315
Pension and OPEB plans	**—**	110
Loss carryforwards	**2,259**	3,081
Other	**1,753**	1,648
Total deferred income tax assets	**4,468**	5,154
Less valuation allowance	**(215)**	(84)
Total deferred income tax assets, net	**4,253**	5,070
Net deferred income tax liabilities	**(13,309)**	(11,201)
Presented as follows:		
Total deferred income tax assets	**472**	488
Total deferred income tax liabilities	**(13,781)**	(11,689)
Net deferred income tax liabilities	**(13,309)**	(11,201)

A valuation allowance has been established for certain loss and credit carryforwards, and outside basis temporary differences on investments that reduce deferred income tax assets to an amount that will more likely than not be realized.

As at December 31, 2022, we recognized the benefit of unused tax loss carryforwards of $2.1 billion (2021 - $1.9 billion) in Canada which expire in 2030 and beyond.

As at December 31, 2022, we recognized the benefit of unused tax loss carryforwards of $8.1 billion (2021 - $11.0 billion) in the US. Unused tax loss carryforwards of $0.2 billion (2021 - $3.5 billion) begin to expire in 2023, and unused tax loss carryforwards of $7.9 billion (2021 - $7.5 billion) have no expiration.

We have not provided for deferred income taxes on the difference between the carrying value of substantially all of our foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such, these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries were $8.0 billion and $4.3 billion for the periods ended December 31, 2022 and 2021, respectively. If such earnings are remitted, in the form of dividends or otherwise, we may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities applicable to such amounts is not practicable.

Enbridge and certain of our subsidiaries are subject to taxation in Canada, the US and other foreign jurisdictions. The material jurisdictions in which we are subject to potential examinations include the US (Federal) and Canada (Federal, Alberta and Québec). We are open to examination by Canadian tax authorities for the 2015 to 2022 tax years and by US tax authorities for the 2019 to 2022 tax years. We are currently under examination for income tax matters in Canada for the 2016 to 2019 tax years. We are not currently under examination for income tax matters in any other material jurisdiction where we are subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**76**	121
Gross increases for tax positions of current year	**—**	1
Gross decreases for tax positions of prior year	**(17)**	(26)
Change in translation of foreign currency	**1**	(1)
Lapses of statute of limitations	**(5)**	(19)
Unrecognized tax benefits at end of year	**55**	76

The unrecognized tax benefits as at December 31, 2022, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Interest and penalties included in income taxes for the years ended December 31, 2022 and 2021 were a $1 million expense and $5 million recovery, respectively. As at December 31, 2022 and 2021, interest and penalties of $13 million and $12 million, respectively, have been accrued.

26. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We sponsor Canadian and US contributory and non-contributory registered defined benefit and defined contribution pension plans, which provide benefits covering substantially all employees. The Canadian pension plans provide defined benefit and defined contribution pension benefits to our Canadian employees. The US pension plans provide defined benefit pension benefits to our US employees. We also sponsor supplemental non-contributory defined benefit pension plans, which provide non-registered benefits for certain employees in Canada and the US.

Defined Benefit Pension Plan Benefits

Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits

Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

Benefit Obligations, Plan Assets and Funded Status

The following table details the changes in the projected benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension plans:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Change in projected benefit obligation				
Projected benefit obligation at beginning of year	**4,600**	4,855	**1,184**	1,243
Service cost	**131**	139	**43**	44
Interest cost	**127**	101	**24**	17
Participant contributions	**29**	28	**—**	—
Actuarial gain[1]	**(1,069)**	(329)	**(201)**	(21)
Benefits paid	**(187)**	(194)	**(94)**	(84)
Foreign currency exchange rate changes	**—**	—	**77**	(11)
Other	**(1)**	—	**(4)**	(4)
Projected benefit obligation at end of year[2]	**3,630**	4,600	**1,029**	1,184
Change in plan assets				
Fair value of plan assets at beginning of year	**4,536**	4,077	**1,160**	1,062
Actual return/(loss) on plan assets	**(235)**	505	**(64)**	151
Employer contributions[3]	**91**	120	**4**	43
Participant contributions	**29**	28	**—**	—
Benefits paid	**(187)**	(194)	**(94)**	(84)
Foreign currency exchange rate changes	**—**	—	**78**	(8)
Other	**—**	—	**(4)**	(4)
Fair value of plan assets at end of year[4]	**4,234**	4,536	**1,080**	1,160
Overfunded/(underfunded) status at end of year	**604**	(64)	**51**	(24)
Presented as follows:				
Deferred amounts and other assets	**764**	250	**141**	98
Accounts payable and other	**(9)**	(9)	**(5)**	(4)
Other long-term liabilities	**(151)**	(305)	**(85)**	(118)
	604	(64)	**51**	(24)

1 Actuarial gains in 2022 and 2021 primarily due to increase in the discount rates used to measure the benefit obligations.

2 The accumulated benefit obligation for our Canadian pension plans was $3.4 billion and $4.3 billion as at December 31, 2022 and 2021, respectively. The accumulated benefit obligation for our US pension plans was $1.0 billion and $1.1 billion as at December 31, 2022 and 2021, respectively.

3 Lower employer contributions in 2022 compared to 2021 primarily due to more plans in an overfunded status.

4 Assets in the amount of $10 million (2021 - $13 million) and $58 million (2021 - $84 million), related to our Canadian and US non-registered supplemental pension plan obligations, are held in grantor trusts and rabbi trusts that, in accordance with federal tax regulations, are not restricted from creditors. These assets are committed for the future settlement of benefit obligations included in the underfunded status as at the end of the year, however they are excluded from plan assets for accounting purposes.

Certain of our pension plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Accumulated benefit obligation	**360**	440	**89**	115
Fair value of plan assets	**218**	247	**—**	—

Certain of our pension plans have projected benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Projected benefit obligation	**377**	1,272	**90**	121
Fair value of plan assets	**218**	1,020	**—**	—

Amount Recognized in Accumulated Other Comprehensive Income
The amount of pre-tax AOCI relating to our pension plans are as follows:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Net actuarial (gain)/loss	**(64)**	226	**40**	92
Prior service (credit)/cost	**—**	—	**1**	(1)
Total amount recognized in AOCI[1]	**(64)**	226	**41**	91

1 Excludes amounts related to CTA.

Net Periodic Benefit Cost and Other Amounts Recognized in Comprehensive Income
The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension plans are as follows:

	Canada			US		
Year ended December 31,	**2022**	2021	2020	**2022**	2021	2020
(millions of Canadian dollars)						
Service cost	**131**	139	148	**43**	44	44
Interest cost[1]	**127**	101	128	**24**	17	31
Expected return on plan assets[1]	**(295)**	(252)	(260)	**(85)**	(73)	(88)
Amortization/settlement of net actuarial loss[1]	**8**	54	42	**—**	11	1
Amortization/curtailment of prior service credit[1]	**—**	—	—	**(2)**	—	(1)
Net periodic benefit (credit)/cost	**(29)**	42	58	**(20)**	(1)	(13)
Defined contribution benefit cost	**10**	7	6	**—**	—	—
Net pension (credit)/cost recognized in Earnings	**(19)**	49	64	**(20)**	(1)	(13)
Amount recognized in OCI:						
Amortization/settlement of net actuarial loss	**(2)**	(25)	(21)	**—**	(11)	(1)
Amortization/curtailment of prior service credit	**—**	—	—	**2**	—	1
Net actuarial (gain)/loss arising during the year	**(288)**	(291)	118	**(52)**	(99)	100
Total amount recognized in OCI	**(290)**	(316)	97	**(50)**	(110)	100
Total amount recognized in Comprehensive income	**(309)**	(267)	161	**(70)**	(111)	87

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

Actuarial Assumptions
The weighted average assumptions made in the measurement of the projected benefit obligation and net periodic benefit cost of our pension plans are as follows:

	Canada			US		
	2022	2021	2020	**2022**	2021	2020
Projected benefit obligation						
Discount rate	**5.1 %**	3.2 %	2.6 %	**4.9 %**	2.6 %	2.2 %
Rate of salary increase	**2.9 %**	2.9 %	2.3 %	**2.8 %**	2.8 %	2.7 %
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.3 %**	4.3 %	4.3 %
Net periodic benefit cost						
Discount rate	**3.2 %**	2.6 %	3.0 %	**2.6 %**	2.2 %	3.0 %
Rate of return on plan assets	**6.6 %**	6.2 %	6.8 %	**7.4 %**	7.3 %	7.9 %
Rate of salary increase	**2.9 %**	2.3 %	3.2 %	**2.8 %**	2.7 %	2.9 %
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.3 %**	4.3 %	4.5 %

OTHER POSTRETIREMENT BENEFIT PLANS
We sponsor funded and unfunded defined benefit OPEB Plans, which provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees.

Benefit Obligations, Plan Assets and Funded Status
The following table details the changes in the accumulated postretirement benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit OPEB plans:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Change in accumulated postretirement benefit obligation				
Accumulated postretirement benefit obligation at beginning of year	**274**	321	**173**	254
Service cost	**4**	6	**1**	1
Interest cost	**7**	7	**3**	3
Participant contributions	**—**	—	**6**	8
Actuarial gain[1]	**(66)**	(51)	**(37)**	(69)
Benefits paid	**(8)**	(9)	**(21)**	(22)
Foreign currency exchange rate changes	**—**	—	**11**	(3)
Other	**—**	—	**—**	1
Accumulated postretirement benefit obligation at end of year	**211**	274	**136**	173
Change in plan assets				
Fair value of plan assets at beginning of year	**—**	—	**201**	188
Actual return/(loss) on plan assets	**—**	—	**(21)**	22
Employer contributions	**8**	9	**7**	6
Participant contributions	**—**	—	**6**	8
Benefits paid	**(8)**	(9)	**(21)**	(22)
Foreign currency exchange rate changes	**—**	—	**13**	(3)
Other	**—**	—	**—**	2
Fair value of plan assets at end of year	**—**	—	**185**	201
Overfunded/(underfunded) status at end of year	**(211)**	(274)	**49**	28
Presented as follows:				
Deferred amounts and other assets	**—**	—	**75**	71
Accounts payable and other	**(12)**	(12)	**—**	—
Other long-term liabilities	**(199)**	(262)	**(26)**	(43)
	(211)	(274)	**49**	28

1 Actuarial gains in 2022 and 2021 primarily due to increase in the discount rates used to measure the benefit obligations.

Certain of our OPEB plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Accumulated benefit obligation	**211**	274	**76**	94
Fair value of plan assets	**—**	—	**50**	51

Amount Recognized in Accumulated Other Comprehensive Income
The amount of pre-tax AOCI relating to our OPEB plans are as follows:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Net actuarial gain	**(101)**	(35)	**(102)**	(104)
Prior service credit	**(1)**	(1)	**(30)**	(37)
Total amount recognized in AOCI[1]	**(102)**	(36)	**(132)**	(141)

1 Excludes amounts related to CTA.

Net Periodic Benefit Cost and Other Amounts Recognized in Comprehensive Income
The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our OPEB plans are as follows:

	Canada			US		
Year ended December 31,	**2022**	2021	2020	**2022**	2021	2020
(millions of Canadian dollars)						
Service cost	**4**	6	5	**1**	1	2
Interest cost[1]	**7**	7	8	**3**	3	7
Expected return on plan assets[1]	**—**	—	—	**(12)**	(10)	(12)
Amortization/settlement of net actuarial gain[1]	**(1)**	—	(1)	**(6)**	(1)	(1)
Amortization/curtailment of prior service credit[1]	**—**	—	—	**(7)**	(7)	(2)
Net periodic benefit (credit)/cost recognized in Earnings	**10**	13	12	**(21)**	(14)	(6)
Amount recognized in OCI:						
Amortization/settlement of net actuarial gain	**1**	—	1	**6**	1	1
Amortization/curtailment of prior service credit	**—**	—	—	**7**	7	2
Net actuarial (gain)/loss arising during the year	**(67)**	(50)	21	**(4)**	(80)	15
Prior service credit	**—**	—	—	**—**	—	(33)
Total amount recognized in OCI	**(66)**	(50)	22	**9**	(72)	(15)
Total amount recognized in Comprehensive income	**(56)**	(37)	34	**(12)**	(86)	(21)

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

The weighted average assumptions made in the measurement of the accumulated postretirement benefit obligation and net periodic benefit cost of our OPEB plans are as follows:

	Canada			US		
	2022	2021	2020	**2022**	2021	2020
Accumulated postretirement benefit obligation						
Discount rate	**5.3 %**	3.2 %	2.6 %	**4.9 %**	2.4 %	2.0 %
Net periodic benefit cost						
Discount rate	**3.2 %**	2.6 %	3.1 %	**2.4 %**	2.0 %	2.8 %
Rate of return on plan assets	**N/A**	N/A	N/A	**6.0 %**	6.0 %	6.7 %

Assumed Health Care Cost Trend Rates
The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Canada		US[1]	
	2022	2021	**2022**	2021
Health care cost trend rate assumed for next year	**4.0 %**	4.0 %	**4.7 %**	7.0 %
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0 %**	4.0 %	**3.3 %**	4.5 %
Year that the rate reaches the ultimate trend rate	**N/A**	N/A	**2021 - 2045**	2037

1 In addition, under the Enbridge Employee Services, Inc., Health Reimbursement Account Plan, health care costs will increase by 5.0% every three years.

PLAN ASSETS
We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

	Canada			US		
	Target	December 31,		**Target**	December 31,	
Asset Category	**Allocation**	**2022**	2021	**Allocation**	**2022**	2021
Equity securities	**43.8 %**	**38.2 %**	46.7 %	**45.0 %**	**38.3 %**	52.5 %
Fixed income securities	**28.4 %**	**31.7 %**	29.8 %	**20.0 %**	**20.5 %**	18.4 %
Alternatives[1]	**27.8 %**	**30.1 %**	23.5 %	**35.0 %**	**41.2 %**	29.1 %

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.

Pension Plans

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

	Canada				US			
	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
December 31, 2022								
Cash and cash equivalents	**272**	**—**	**—**	**272**	**13**	**—**	**—**	**13**
Equity securities								
Canada	**—**	**355**	**—**	**355**	**—**	**—**	**—**	**—**
Global	**—**	**1,263**	**—**	**1,263**	**—**	**414**	**—**	**414**
Fixed income securities								
Government	**201**	**435**	**—**	**636**	**—**	**87**	**—**	**87**
Corporate	**—**	**433**	**—**	**433**	**—**	**121**	**—**	**121**
Alternatives[4]	**—**	**—**	**1,291**	**1,291**	**—**	**—**	**445**	**445**
Forward currency contracts	**—**	**(16)**	**—**	**(16)**	**—**	**—**	**—**	**—**
Total pension plan assets at fair value	**473**	**2,470**	**1,291**	**4,234**	**13**	**622**	**445**	**1,080**
December 31, 2021								
Cash and cash equivalents	180	—	—	180	10	—	—	10
Equity securities								
Canada	198	228	—	426	—	—	—	—
US	1	—	—	1	—	—	—	—
Global	—	1,693	—	1,693	—	609	—	609
Fixed income securities								
Government	258	459	—	717	—	86	—	86
Corporate	—	453	—	453	—	118	—	118
Alternatives[4]	—	—	1,064	1,064	—	—	337	337
Forward currency contracts	—	2	—	2	—	—	—	—
Total pension plan assets at fair value	637	2,835	1,064	4,536	10	813	337	1,160

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of pension plan assets classified as Level 3 in the fair value hierarchy were as follows:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Balance at beginning of year	**1,064**	912	**337**	289
Unrealized and realized gains	**155**	77	**78**	38
Purchases and settlements, net	**72**	75	**30**	10
Balance at end of year	**1,291**	1,064	**445**	337

OPEB Plans
The following table summarizes the fair value of plan assets for our US funded OPEB plans recorded at each fair value hierarchy level:

	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)				
December 31, 2022				
Cash and cash equivalents	**2**	**—**	**—**	**2**
Equity securities				
US	**—**	**34**	**—**	**34**
Global	**—**	**62**	**—**	**62**
Fixed income securities				
Government	**46**	**5**	**—**	**51**
Corporate	**—**	**8**	**—**	**8**
Alternatives[4]	**—**	**—**	**28**	**28**
Total OPEB plan assets at fair value	**48**	**109**	**28**	**185**
December 31, 2021				
Cash and cash equivalents	4	—	—	4
Equity securities				
US	—	39	—	39
Global	—	75	—	75
Fixed income securities				
Government	47	6	—	53
Corporate	—	8	—	8
Alternatives[4]	—	—	22	22
Total OPEB plan assets at fair value	51	128	22	201

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives includes investments in private debt, private equity, infrastructure and real estate.

Changes in the net fair value of US funded OPEB plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Balance at beginning of year	**22**	22
Unrealized and realized gains	**4**	2
Purchases and settlements, net	**2**	(2)
Balance at end of year	**28**	22

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2023	2024	2025	2026	2027	2028-2032
(millions of Canadian dollars)						
Pension						
Canada	204	210	216	221	226	1,208
US	88	87	87	88	90	424
OPEB						
Canada	12	12	13	13	13	68
US	16	15	14	13	12	49

EXPECTED EMPLOYER CONTRIBUTIONS
In 2023, we expect to contribute approximately $29 million and $5 million to the Canadian and US pension plans, respectively, and $12 million and $6 million to the Canadian and US OPEB plans, respectively.

RETIREMENT SAVINGS PLANS
In addition to the pension and OPEB plans discussed above, we also have defined contribution employee savings plans available to US employees. Employees may participate in a matching contribution where we match a certain percentage of before-tax employee contributions of up to 6.0% of eligible pay per pay period. For the year ended December 31, 2022, pre-tax employer matching contribution costs were $30 million ($27 million in each of 2021 and 2020).

27. LEASES

LESSEE
We incur operating lease expenses related primarily to real estate, pipelines, storage and equipment. Our operating leases have remaining lease terms of 1 month to 24 years as at December 31, 2022.

For the years ended December 31, 2022, 2021 and 2020, we incurred operating lease expenses of $118 million, $95 million and $107 million, respectively. Operating lease expenses are reported under Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2022, 2021 and 2020, operating lease payments to settle lease liabilities were $123 million, $118 million and $133 million, respectively. Operating lease payments are reported under Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Statements of Financial Position Information

(millions of Canadian dollars, except lease term and discount rate)	**December 31, 2022**	December 31, 2021
Operating leases[1]		
Operating lease right-of-use assets, net[2]	**680**	645
Operating lease liabilities - current[3]	**87**	92
Operating lease liabilities - long-term[3]	**677**	612
Total operating lease liabilities	**764**	704
Finance leases		
Finance lease right-of-use assets, net[4]	**62**	49
Finance lease liabilities - current[5]	**17**	13
Finance lease liabilities - long-term[3]	**39**	33
Total finance lease liabilities	**56**	46
Weighted average remaining lease term		
Operating leases	**12 years**	12 years
Finance leases	**5 years**	7 years
Weighted average discount rate		
Operating leases	**4.2 %**	4.1 %
Finance leases	**4.4 %**	3.8 %

1 Affiliate ROU assets, current lease liabilities and long-term lease liabilities as at December 31, 2022 were $47 million (December 31, 2021 - $51 million), $5 million (December 31, 2021 - $5 million) and $43 million (December 31, 2021 - $47 million), respectively.
2 Operating lease ROU assets are reported under Deferred amounts and other assets in the Consolidated Statements of Financial Position.
3 Current operating lease liabilities and long-term operating and finance lease liabilities are reported under Accounts payable and other and Other long-term liabilities, respectively, in the Consolidated Statements of Financial Position.
4 Finance lease ROU assets are reported under Property, plant and equipment, net in the Consolidated Statements of Financial Position.
5 Current finance lease liabilities are reported under Current portion of long-term debt in the Consolidated Statements of Financial Position.

As at December 31, 2022, our operating and finance lease liabilities are expected to mature as follows:

(millions of Canadian dollars)	**Operating leases**	**Finance leases**
2023	**109**	**19**
2024	**110**	**16**
2025	**104**	**8**
2026	**90**	**8**
2027	**82**	**1**
Thereafter	**489**	**10**
Total undiscounted lease payments	**984**	**62**
Less imputed interest	**(220)**	**(6)**
Total	**764**	**56**

LESSOR

We receive revenues from operating leases primarily related to natural gas and crude oil storage and processing facilities, rail cars, and wind power generation assets. Our operating leases have remaining lease terms of 1 month to 29 years as at December 31, 2022.

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating lease income	**266**	263	265
Variable lease income	**321**	333	361
Total lease income[1]	**587**	596	626

1 Lease income is recorded under Transportation and other services in the Consolidated Statements of Earnings.

As at December 31, 2022, our future lease payments to be received under operating lease contracts where we are the lessor are as follows:

	Operating leases
(millions of Canadian dollars)	
2023	**227**
2024	**215**
2025	**204**
2026	**198**
2027	**201**
Thereafter	**1,832**
Future lease payments	**2,877**

28. OTHER INCOME/(EXPENSE)

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Gain/(loss) on dispositions	**(12)**	319	(17)
Realized foreign currency gain/(loss)	**92**	126	(10)
Unrealized foreign currency gain/(loss)	**(1,094)**	160	191
Net defined pension and OPEB credit	**239**	150	148
Other	**186**	224	(74)
	(589)	979	238

29. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Accounts receivable and other	**(967)**	(1,228)	1,546
Accounts receivable from affiliates	**17**	(38)	8
Inventory	**(599)**	(118)	(254)
Deferred amounts and other assets	**1**	(195)	(586)
Accounts payable and other	**1,100**	87	(770)
Accounts payable to affiliates	**16**	52	1
Interest payable	**58**	43	31
Other long-term liabilities	**362**	(69)	117
	(12)	(1,466)	93

30. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

We provide transportation services to several significantly influenced investees which we record as transportation and other services revenue. We also purchase and sell natural gas and crude oil with several of our significantly influenced investees. These revenues and costs are recorded as commodity sales and commodity costs. We contract for firm transportation services to meet our annual natural gas supply requirements which we record as gas distribution costs.

Our transactions with significantly influenced investees are as follows:

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Transportation and other revenues	**185**	237	219
Commodity sales	**51**	20	21
Operating and administrative[1]	**503**	380	338
Commodity costs[2]	**778**	790	518
Gas distribution costs	**136**	131	135

1 *During the years ended December 31, 2022, 2021 and 2020, we had Operating and administrative costs from the Seaway Crude Pipeline System of $495 million, $389 million and $342 million, respectively. These costs are a result of an operational contract where we utilize capacity on Seaway Crude Pipeline System assets for use in our Liquids Pipelines business.*

2 *During the years ended December 31, 2022, 2021 and 2020, we had Commodity costs from Aux Sable Canada LP of $571 million, $447 million and $91 million, respectively.*

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

As at December 31, 2022, amounts receivable from affiliates include a series of loans totaling $752 million (2021 - $954 million), which require quarterly or semi-annual interest payments at annual interest rates ranging from 3% to 8%. Interest income recognized from these notes totaled $30 million, $39 million and $44 million for the years ended December 31, 2022, 2021 and 2020, respectively. The amounts receivable from affiliates are included in Deferred amounts and other assets in the Consolidated Statements of Financial position.

31. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2022, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	78,742	6,024	8,220	6,051	3,730	10,344	44,373
Purchase of services, pipe and other materials, including transportation[2]	10,661	3,553	1,513	1,070	1,001	767	2,757
Maintenance agreements[3]	536	53	53	53	53	55	269
Right-of-ways commitments	1,474	45	45	46	46	46	1,246
Total	91,413	9,675	9,831	7,220	4,830	11,212	48,645

1 Includes debentures, term notes, commercial paper and credit facility draws based on the facility's maturity date and excludes short-term borrowings, debt discounts, debt issuance costs, finance lease obligations and fair value adjustment. We have the ability under certain debt facilities to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.

2 Includes capital and operating commitments. Consists primarily of firm capacity payments that provide us with uninterrupted firm access to natural gas and crude oil transportation and storage contracts; contractual obligations to purchase physical quantities of natural gas; and power commitments.

3 Consists primarily of maintenance service contracts for our wind and solar assets.

ENVIRONMENTAL

We are subject to various Canadian and US federal, provincial/state and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and Enbridge and its affiliates are, at times, subject to environmental remediation obligations at various sites where we operate. We manage this environmental risk through appropriate environmental policies, programs and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of costs arising from environmental incidents associated with our operating activities.

AUX SABLE

On October 14, 2016, an amended claim was filed against Aux Sable by a counterparty to an NGL supply agreement. On January 5, 2017, Aux Sable filed a Statement of Defence with respect to this claim.

On November 27, 2019, the counterparty filed an amended amended claim providing further particulars of its claim against Aux Sable, increasing its damages claimed, and adding defendants Aux Sable Liquid Products Inc. and Aux Sable Extraction LLC (general partners of the previously existing defendants). Aux Sable filed an amended Statement of Defence responding to the amended amended claim on January 31, 2020.

While the final outcome of this action cannot be predicted with certainty, at this time management believes that the ultimate resolution of this action will not have a material impact on our consolidated financial position or results of operations.

OTHER LITIGATION
We and our subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS
We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

INSURANCE
We maintain a comprehensive insurance program for us, our operating subsidiaries and certain equity investments. This program includes insurance coverage in types and amounts and is subject to certain deductibles, terms, exclusions and conditions that are generally consistent with coverage considered customary for our industry, however insurance does not cover all events in all circumstances. We self-insure a significant portion of expected losses relating to certain insurance property and casualty risk exposures in the US and Canada through our wholly-owned captive insurance subsidiaries.

In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among entities on an equitable basis based on an insurance allocation agreement we have entered into with us and other subsidiaries. Insurance estimates include certain assumptions and management judgments regarding the frequency and severity of claims, claim development and settlement practices and the selection of estimated loss among estimates derived using different methods.

32. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included in our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2022, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

33. QUARTERLY FINANCIAL DATA (UNAUDITED)

	Q1	Q2	Q3	Q4	Total
(unaudited; millions of Canadian dollars, except per share amounts)					
2022					
Operating revenues	**15,097**	**13,215**	**11,573**	**13,424**	**53,309**
Operating income/(loss)	**2,420**	**1,520**	**1,778**	**(540)**	**5,178**
Earnings/(loss)	**2,057**	**607**	**1,383**	**(1,109)**	**2,938**
Earnings/(loss) attributable to controlling interests	**2,029**	**595**	**1,362**	**(983)**	**3,003**
Earnings/(loss) attributable to common shareholders	**1,927**	**450**	**1,279**	**(1,067)**	**2,589**
Earnings/(loss) per common share					
Basic	**0.95**	**0.22**	**0.63**	**(0.53)**	**1.28**
Diluted	**0.95**	**0.22**	**0.63**	**(0.53)**	**1.28**
2021					
Operating revenues	12,187	10,948	11,466	12,470	47,071
Operating income	2,548	1,816	1,388	2,053	7,805
Earnings	2,014	1,521	814	1,965	6,314
Earnings attributable to controlling interests	1,992	1,484	780	1,933	6,189
Earnings attributable to common shareholders	1,900	1,394	682	1,840	5,816
Earnings per common share					
Basic	0.94	0.69	0.34	0.91	2.87
Diluted	0.94	0.69	0.34	0.91	2.87

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES
Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and US securities law. As at December 31, 2022, an evaluation was carried out under the supervision of and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of our disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by us in reports that we file with or submit to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

INTERNAL CONTROL OVER FINANCIAL REPORTING
Management's Annual Report on Internal Control over Financial Reporting
Our management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the SEC and the Canadian Securities Administrators. Our internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external reporting purposes in accordance with US GAAP.

Our internal control over financial reporting includes policies and procedures that:
- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Our internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with our policies and procedures.

Our management assessed the effectiveness of our internal control over financial reporting as at December 31, 2022, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that we maintained effective internal control over financial reporting as at December 31, 2022.

The effectiveness of our internal control over financial reporting as at December 31, 2022 has been audited by PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm appointed by our shareholders. As stated in their *Report of Independent Registered Public Accounting Firm* which appears in *Item 8. Financial Statements and Supplementary Data*, they expressed an unqualified opinion on the effectiveness of our internal control over financial reporting as at December 31, 2022.

Changes in Internal Control Over Financial Reporting
During the three months ended December 31, 2022, there has been no material change in our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

NORMAL COURSE ISSUER BID
On January 4, 2023, we announced that the TSX had approved our new NCIB to purchase, for cancellation, up to 27,938,163 of the outstanding common shares of Enbridge to an aggregate amount of up to $1.5 billion.

Purchases under the NCIB may be made through the facilities of the TSX, the NYSE and other designated exchanges and alternative trading systems, commencing on January 6, 2023 and continuing until January 5, 2024, when the NCIB expires, or such earlier date on which Enbridge has either acquired the maximum number of common shares allowable under the NCIB or otherwise decided not to make any further repurchases under the NCIB.

A copy of our notice of intention to make a normal course issuer bid may be obtained, free of charge, by contacting Investor Relations by email, phone or mail at:

Email: investor.relations@enbridge.com
Phone Within North America: 1-800-481-2804
Phone Outside North America: 1-403-231-3960
Mail: Enbridge Inc. Investor Relations, 200, 425 – 1st Street S.W., Calgary, Alberta, Canada T2P 3L8

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors of Registrant
The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2022. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

Executive Officers of Registrant
The information regarding executive officers is included in Part I. *Item 1. Business - Executive Officers.*

Code of Ethics for Chief Executive Officer and Senior Financial Officers
The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2022. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2022. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2022. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2022. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2022. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Enbridge Inc.:

Report of Independent Registered Public Accounting Firm (PCAOB ID 271)
Consolidated Statements of Earnings
Consolidated Statements of Comprehensive Income
Consolidated Statements of Changes in Equity
Consolidated Statements of Cash Flows
Consolidated Statements of Financial Position
Notes to the Consolidated Financial Statements

All schedules are omitted because they are not required or because the required information is included in the Consolidated Financial Statements or Notes.

(b) Exhibits:

Reference is made to the “Index of Exhibits” following *Item 16. Form 10-K Summary*, which is hereby incorporated into this Item.

ITEM 16. FORM 10-K SUMMARY

Not applicable.

INDEX OF EXHIBITS

Each exhibit identified below is included as a part of this annual report. Exhibits included in this filing are designated by an asterisk ("*"); all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement.

Exhibit No.		Name of Exhibit
3.1		Articles of Continuance of the Corporation, dated December 15, 1987 (incorporated by reference to Exhibit 2.1(a) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.2		Certificate of Amendment, dated August 2, 1989, to the Articles of the Corporation (incorporated by reference to Exhibit 2.1(b) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.3		Articles of Amendment of the Corporation, dated April 30, 1992 (incorporated by reference to Exhibit 2.1(c) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.4		Articles of Amendment of the Corporation, dated July 2, 1992 (incorporated by reference to Exhibit 2.1(d) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.5		Articles of Amendment of the Corporation, dated August 6, 1992 (incorporated by reference to Exhibit 2.1(e) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.6		Articles of Arrangement of the Corporation dated December 18, 1992, attaching the Arrangement Agreement, dated December 15, 1992 (incorporated by reference to Exhibit 2.1(f) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.7		Certificate of Amendment of the Corporation (notarial certified copy), dated December 18, 1992 (incorporated by reference to Exhibit 2.1(g) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.8		Articles of Amendment of the Corporation, dated May 5, 1994 (incorporated by reference to Exhibit 2.1(h) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.9		Certificate of Amendment, dated October 7, 1998 (incorporated by reference to Exhibit 2.1(i) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.10		Certificate of Amendment, dated November 24, 1998 (incorporated by reference to Exhibit 2.1(j) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.11		Certificate of Amendment, dated April 29, 1999 (incorporated by reference to Exhibit 2.1(k) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.12		Certificate of Amendment, dated May 5, 2005 (incorporated by reference to Exhibit 2.1(l) to Enbridge's Registration Statement on Form S-8 filed August 5, 2005)
3.13		Certificate of Amendment, dated May 11, 2011 (incorporated by reference to Exhibit 3.13 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.14		Certificate of Amendment, dated September 28, 2011 (incorporated by reference to Exhibit 3.14 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.15		Certificate of Amendment, dated November 21, 2011 (incorporated by reference to Exhibit 3.15 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)

3.16		Certificate of Amendment, dated January 16, 2012 (incorporated by reference to Exhibit 3.16 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.17		Certificate of Amendment, dated March 27, 2012 (incorporated by reference to Exhibit 3.17 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.18		Certificate of Amendment, dated April 16, 2012 (incorporated by reference to Exhibit 3.18 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.19		Certificate of Amendment, dated May 17, 2012 (incorporated by reference to Exhibit 3.19 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.20		Certificate of Amendment, dated July 12, 2012 (incorporated by reference to Exhibit 3.20 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.21		Certificate of Amendment, dated September 11, 2012 (incorporated by reference to Exhibit 3.21 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.22		Certificate of Amendment, dated December 3, 2012 (incorporated by reference to Exhibit 3.22 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.23		Certificate of Amendment, dated March 25, 2013 (incorporated by reference to Exhibit 3.23 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.24		Certificate of Amendment, dated June 4, 2013 (incorporated by reference to Exhibit 3.24 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.25		Certificate of Amendment, dated September 25, 2013 (incorporated by reference to Exhibit 3.25 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.26		Certificate of Amendment, dated December 10, 2013 (incorporated by reference to Exhibit 3.26 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.27		Certificate of Amendment, dated March 10, 2014 (incorporated by reference to Exhibit 3.27 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.28		Certificate of Amendment, dated May 20, 2014 (incorporated by reference to Exhibit 3.28 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.29		Certificate of Amendment, dated July 15, 2014 (incorporated by reference to Exhibit 3.29 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.30		Certificate of Amendment, dated September 19, 2014 (incorporated by reference to Exhibit 3.30 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.31		Certificate of Amendment, dated November 22, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 1, 2016)
3.32		Certificate of Amendment, dated December 15, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 16, 2016)
3.33		Certificate of Amendment, dated July 13, 2017 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed July 13, 2017)
3.34		Certificate of Amendment, dated September 25, 2017 (incorporated by reference to Exhibit 3.34 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
3.35		Certificate of Amendment, dated December 7, 2017 (incorporated by reference to Exhibit 3.35 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
3.36		Certificate of Amendment, dated February 27, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed March 1, 2018)

3.37		Certificate of Amendment, dated April 9, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed April 12, 2018)
3.38		Certificate of Amendment, dated April 10, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed April 12, 2018)
3.39		Certificate and Articles of Amendment, dated July 6, 2020 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed July 8, 2020)
3.40		Certificate of Amendment, dated January 17, 2022 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed January 20, 2022)
3.41		Certificate of Amendment, dated January September 15, 2022 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed September 20, 2022)
3.42		Certificate of Amendment, dated January September 15, 2022 (incorporated by reference to Exhibit 3.2 to Enbridge's Current Report on Form 8-K filed September 20, 2022)
3.43		General By-Law No. 1 of Enbridge Inc. (incorporated by reference to Exhibit 3.40 to Enbridge's Form 10-K filed February 11, 2022)
3.44		By-Law No. 2 of Enbridge Inc. (incorporated by reference to Enbridge's Current Report on Form 6-K filed December 5, 2014)
4.1		Form of Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas to be dated February 25, 2005 (incorporated by reference to Exhibit 7.1 to Enbridge's Registration Statement on Form F-10 filed February 4, 2005)
4.2		First Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated March 1, 2012 (incorporated by reference to Exhibit 7.3 to Enbridge's Registration Statement on Form F-10 filed May 11, 2012)
4.3		Second Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated December 19, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 20, 2016)
4.4		Third Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated July 14, 2017 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed July 14, 2017)
4.5		Fourth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated March 1, 2018 (incorporated by reference to Enbridge's Current Report on Form 8-K filed March 1, 2018)
4.6		Fifth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated April 12, 2018 (incorporated by reference to Enbridge's Current Report on Form 8-K filed April 12, 2018)
4.7		Sixth Supplemental Indenture between Enbridge Inc., Spectra Energy Partners, LP (as guarantor), Enbridge Energy Partners, L.P. (as guarantor) and Deutsche Bank Trust Company Americas, dated May 13, 2019 (incorporated by reference to Enbridge's Registration Statement on Form S-3 filed May 17, 2019)
4.8		Seventh Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated July 8, 2020 (incorporated by reference to Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed July 8, 2020)
4.9		Eighth Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated June 28, 2021 (incorporated by reference to Exhibit 4.4 to Enbridge's Current Report on Form 8-K filed June 28, 2021)
4.10		Ninth Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated September 20, 2022 (incorporated by reference to Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed September 20, 2022)

4.11		Tenth Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated September 20, 2022 (incorporated by reference to Exhibit 4.2 to Enbridge's Current Report on Form 8-K filed September 20, 2022)
4.12		Shareholder Rights Plan Agreement between Enbridge Inc. and Computershare Trust Company of Canada dated as of November 9, 1995 and Amended and Restated as of May 5, 2020 (incorporated by reference to Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed May 6, 2020).
4.13		Description of Securities Registered Under Section 12 of the Securities Exchange Act, as amended (incorporated by reference to Exhibit 4.9 to Enbridge's Form 10-K filed February 14, 2020)
		Certain instruments defining the rights of holders of long-term debt securities of the Registrant and its subsidiaries are omitted pursuant to Item 601(b)(4)(iii) of Regulation S-K. The Registrant hereby undertakes to furnish to the SEC, upon request, copies of any such instruments.
10.1		Enbridge Pipelines Inc. Competitive Toll Settlement dated July 1, 2011 (incorporated by reference to Exhibit 10.1 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.2		Sixteenth Supplemental Indenture dated as of January 22, 2019 between Enbridge Energy Partners, L.P. and US Bank National Association, as trustee (incorporated by reference as Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.3		Seventeenth Supplemental Indenture dated as of January 22, 2019 between Enbridge Energy Partners, L.P., Enbridge Inc. and US Bank National Association, as trustee (incorporated by reference as Exhibit 4.2 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.4		Seventh Supplemental Indenture dated as of January 22, 2019 between Spectra Energy Partners, LP, Enbridge Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference as Exhibit 4.3 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.5		Eighth Supplemental Indenture dated as of January 22, 2019 between Spectra Energy Partners, LP, Enbridge Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference as Exhibit 4.4 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.6		Subsidiary Guarantee Agreement dated as of January 22, 2019 between Spectra Energy Partners, LP and Enbridge Energy Partners, L.P. (incorporated by reference as Exhibit 4.5 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.7	+	Form of Executive Employment Agreement (pre-2014) (incorporated by reference to Exhibit 10.2 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.8	+	Form of Executive Employment Agreement (2014-2016) (incorporated by reference to Exhibit 10.3 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.9	+	Form of Executive Employment Agreement (2017) (incorporated by reference to Exhibit 10.4 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.10	+	Executive Employment Agreement between Enbridge Employee Services, Inc. and William T. Yardley, dated July 25, 2018 (incorporated by reference to Exhibit 10.1 to Enbridge's Form 8-K filed July 27, 2018)
10.11	+	Form of Executive Employment Agreement (2022) with Enbridge Employee Services, Inc. (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed on July 29, 2022)
10.12	+	Form of Director Indemnity Agreement (2015) (incorporated by reference to Exhibit 10.11 to Enbridge's Annual Report on Form 10-K filed February 15, 2019)

10.13	+	Enbridge Inc. 2019 Long Term Incentive Plan (incorporated by reference to Appendix A to Enbridge's Proxy Statement on Schedule 14A for Enbridge's Annual Meeting of Shareholders (File No. 001-15254) filed March 27, 2019)
10.14		Form of Enbridge Inc. 2019 Long-Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Grant Unit Award Agreement (Share-settled) – Retention Award Version (incorporated by reference to Exhibit 99.1 to Enbridge's 8-K filed November 30, 2022)
10.15	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (2021) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 7, 2021)
10.16	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (2021) (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 7, 2021)
10.17	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2021 Share-settled) (incorporated by reference to Exhibit 10.3 to Enbridge's Form 10-Q filed May 7, 2021)
10.18	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2021 Cash-settled) (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 7, 2021)
10.19	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit - Energy Marketers Grant Notice and Restricted Stock Unit Award Agreement (2021) (incorporated by reference to Exhibit 10.5 to Enbridge's Form 10-Q filed May 7, 2021)
10.20	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (2020) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 7, 2020)
10.21	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (2020) (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 7, 2020)
10.22	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2020 Share-settled) (incorporated by reference to Exhibit 10.3 to Enbridge's Form 10-Q filed May 7, 2020)
10.23	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2020 Cash-settled) (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 7, 2020)
10.24	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 10, 2019)
10.25	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (incorporated by reference to Exhibit 10.5 to Enbridge's Form 10-Q filed May 10, 2019)
10.26	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.6 to Enbridge's Form 10-Q filed May 10, 2019)
10.27	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit - Energy Marketers Grant Notice and Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.7 to Enbridge's Form 10-Q filed May 10, 2019)
10.28	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement - Retention Award Version (incorporated by reference to Exhibit 10.8 to Enbridge's Form 10-Q filed August 2, 2019)

10.29	+	Enbridge Inc. Incentive Stock Option Plan (2007), as amended and restated (2011) (incorporated by reference to Exhibit 10.13 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.30	+	Enbridge Inc. Incentive Stock Option Plan (2007), as amended and restated (2011 and 2014) (incorporated by reference to Exhibit 10.14 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.31	+	Enbridge Inc. Incentive Stock Option Plan (2007), as revised (incorporated by reference to Exhibit 10.15 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.32	+	Enbridge Inc. Directors' Compensation Plan dated February 9, 2021, effective April 1, 2021 (incorporated by reference to Exhibit 10.6 to Enbridge's Form 10-Q filed May 7, 2021)
10.33	+	Enbridge Inc. Directors' Compensation Plan dated February 11, 2020, effective January 1, 2020 (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed July 29, 2020).
10.34	+	Enbridge Inc. Directors' Compensation Plan dated February 14, 2018 Amended Effective February 12, 2019 (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 10, 2019)
10.35	+	Enbridge Inc. Directors' Compensation Plan dated February 14, 2018, effective January 1, 2018 (incorporated by reference as Exhibit 10.3 to Enbridge's Form 10-Q filed May 10, 2018)
10.36	+	Enbridge Inc. Directors' Compensation Plan, November 3, 2015, effective January 1, 2016 (incorporated by reference as Exhibit 10.16 to Enbridge's Form 10-K filed February 16, 2018)
10.37	+	Enbridge Inc. Short Term Incentive Plan (As Amended and Restated Effective January 1, 2019) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 10, 2019)
10.38	+	The Enbridge Supplemental Pension Plan, As Amended and Restated Effective January 1, 2018 (incorporated by reference as Exhibit 10.1 to Enbridge's Quarterly Report on Form 10-Q filed May 10, 2018)
10.39	+	Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.20 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.40	+	Amendment 1 and Amendment 2 to the Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.21 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.41	+	Third Amendment to The Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference as Exhibit 10.2 to Enbridge's Quarterly Report on Form 10-Q filed May 10, 2018)
10.42	+*	Fourth Amendment to The Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005)
10.43	+*	Fifth Amendment to The Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005)
10.44	+	Spectra Energy Corp Directors' Savings Plan, as amended and restated (incorporated by reference to Exhibit 10.22 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)

10.45	+	Spectra Energy Corp Executive Savings Plan, as amended and restated (incorporated by reference to Exhibit 10.23 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.46	+	Spectra Energy Executive Cash Balance Plan, as amended and restated (incorporated by reference to Exhibit 10.24 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.47	+	Omnibus Amendment, dated June 20, 2014, to Spectra Energy Corp Executive Savings Plan, Spectra Energy Corp Executive Cash Balance Plan and Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.25 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.48	+	Form of Spectra Energy Corp Stock Option Agreement (Nonqualified Stock Options) (2016) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.49	+	Spectra Energy Corp 2007 Long-Term Incentive Plan (as amended and restated) (incorporated by reference to Exhibit 10.32 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.50	+	Second Amendment to the Spectra Energy Corp Executive Savings Plan (As Amended and Restated Effective May 1, 2012) (incorporated by reference to Exhibit 10.36 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.51	+	Second Amendment to the Spectra Energy Corp Executive Cash Balance Plan (As Amended and Restated Effective May 1, 2012) (incorporated by reference to Exhibit 10.37 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
21.1	*	Subsidiaries of the Registrant
22.1	*	Subsidiary Guarantors
23.1	*	Consent of PricewaterhouseCoopers LLP
24.1		Powers of Attorney (included on the signature page of the Annual Report)
31.1	*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	*	Inline XBRL Document Set for the consolidated financial statements and accompanying notes in Part II. Item 8 "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K
104	*	Cover Page Interactive Date File – the cover page XBRL tags are embedded within the Inline XBRL document (included in Exhibit 101).

SIGNATURES

POWER OF ATTORNEY
Each person whose signature appears below appoints Robert R. Rooney, Vern D. Yu and Karen K. L. Uehara, and each of them, any of whom may act without the joinder of the other, as their true and lawful attorneys-in-fact and agents, with full power of substitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report of Enbridge on Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them or their or his or her substitute and substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE INC.
(Registrant)

Date: February 10, 2023

By: **/s/ Gregory L. Ebel**
Gregory L. Ebel
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 10, 2023 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ Gregory L. Ebel

Gregory L. Ebel
President, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ Vern D. Yu

Vern D. Yu
Executive Vice President, Corporate Development, Chief Financial Officer and President, New Energy Technologies
(Principal Financial Officer)

/s/ Patrick R. Murray

Patrick R. Murray
Senior Vice President and Chief Accounting Officer
(Principal Accounting Officer)

/s/ Pamela L. Carter

Pamela L. Carter
Chair of the Board of Directors

/s/ Mayank (Mike) M. Ashar

Mayank (Mike) M. Ashar
Director

/s/ Gaurdie E. Banister

Gaurdie E. Banister
Director

/s/ Susan M. Cunningham

Susan M. Cunningham
Director

/s/ Jason B. Few

Jason B. Few
Director

/s/ Teresa S. Madden

Teresa S. Madden
Director

/s/ Stephen S. Poloz

Stephen S. Poloz
Director

/s/ S. Jane Rowe

S. Jane Rowe
Director

/s/ Dan C. Tutcher

Dan C. Tutcher
Director

/s/ Steven W. Williams

Steven W. Williams
Director

Execution Copy

Exhibit 10.42

FOURTH AMENDMENT TO THE
ENBRIDGE SUPPLEMENTAL PENSION PLAN FOR UNITED STATES EMPLOYEES
(As Amended and Restated Effective January 1, 2005)

Pursuant to Section 8.1 of the Enbridge Employee Services, Inc. Employees' Supplemental Plan, as amended (the "Supplemental Plan"), and the authority delegated to it by the Board of Directors of Enbridge Employee Services, Inc. (the "EESI Board"), the Human Resources & Compensation Committee of the Enbridge Inc. Board of Directors (the "HRCC") has approved, confirmed, and adopted this Fourth Amendment at a meeting of the HRCC held on the 31st day of July 2018, at which a quorum was present.

1. Effective as of January 1, 2019, Section l.l(ee) of the Supplemental Plan is hereby deleted and replaced, in its entirety, with the following new Section 1.1(ee):

(ee) **"Senior Management Employee"** means an employee of a Participating Company who is employed in a position of Director or above which exceeds the minimum job classification rating for the Company as prescribed by the President and Chief Executive Officer of Enbridge Inc. In order to be a "Senior Management Employee," an employee must be a "member of a select group of management or highly compensated employees" within the meaning such phrase under Sections 201(2), 301(a)(3), and 40l(a)(l) of ERISA.

2. Effective as of January 1, 2019, Section 1.1 of the Supplemental Plan is hereby amended to add the following new Section 1.1(nn) at the end thereof

(nn) **"Participating Company"** means the Company; Spectra Energy Corp; Spectra Energy Operating Company, LLC; and PanEnergy Services, Limited Partnership.

As amended hereby, the Supplemental Plan is hereby specifically ratified and reaffirmed in its entirety.

To record this Fourth Amendment, the undersigned delegate of the HRCC, pursuant to authorization of the HRCC, hereby confirms and executes the Fourth Amendment on this 20th day of December 2018.

By: /s/ Marc Weil
Marc Weil, VP and Chief HR Officer
on behalf of the
Human Resources & Compensation Committee
of the Enbridge Inc. Board of Directors

Exhibit 10.43

FIFTH AMENDMENT TO THE ENBRIDGE SUPPLEMENTAL PENSION PLAN FOR UNITED STATES EMPLOYEES (AS AMENDED AND RESTATED EFFECTIVE JANUARY 1, 2005)

Pursuant to the authority delegated to them by resolutions of the Board of Directors (the "Resolutions") of Enbridge Inc. ("EI") authorizing the transaction described in the Securities Purchase Agreement between Enbridge Gas Distribution Inc. and Liberty Utilities Co. (the "SPA"), the undersigned Chief Human Resources Officer of EI and the Vice President of People Operations, Human Resources of PanEnergy Services, LP hereby adopt this Fifth Amendment to the Enbridge Supplemental Pension Plan for United States Employees (the "Plan"), to be effective as of the SLG Closing (the "Effective Date");

WHEREAS, the Resolutions authorize any two officers of the Corporation or an Affiliate thereof, to take any action that they deem to be necessary or desirable to effectuate the transaction described in the SPA; and

WHEREAS, Section 6.l0(e) of the SPA requires that (i) Saint Lawrence Gas Company, Inc. ("SLG") and any other applicable subsidiary affiliate of SLG cease to be participating employers in the Plan, (ii) the employees and former employees of SLG and its subsidiary affiliates who, immediately prior to the closing of the transaction contemplated in the SPA, have an accrued benefit under the Plan (the "SLG Participants") shall cease participation in the Plan, and (iii) all of the liabilities of the SLG Participants under the Plan shall be assumed by the Buyer or the Affiliate of Buyer, as defined in the SPA.

NOW, THEREFORE, the Plan is hereby amended, effective as of the Effective Date, as follows:

1. ***Plan Section 1.1(t) (definition of "Participating Affiliate") is hereby amended and replaced, in its entirety, as follows:***

(t) **"Participating Affiliate"** means (i) the Company, (ii) Spectra Energy Corp, (iii) Spectra Energy Operating Company LLC, and (iv) PanEnergy Service, Limited Partnership. As of the SLG Closing, St. Lawrence Gas Company, Inc. has ceased to be a Participating Affiliate.

2. ***Plan Section 1.1 is hereby amended to add the following new definitions at the end thereof:***

(oo) **"SLG Buyer Supplemental Plan"** has the definition given to the term "Buyer Supplemental Plan" in the SLG SPA.

(pp) **"SLG Closing"** has the definition given to the term "Closing" in the SLG SPA.

(qq) **"SLG SPA"** means the Securities Purchase Agreement between Enbridge Gas Distribution Inc. and Liberty Utilities Co. dated August 31, 2017, and as it may be amended.

3. ***Addendum D to the Plan is hereby amended to add the following paragraphs at the end thereof:***

Effective as of the SLG Closing, St. Lawrence Gas Company, Inc. shall cease to be an Affiliate. In addition, pursuant to the SLG SPA, effective as of the SLG Closing:

(1) St. Lawrence Gas Company, Inc. shall cease to be a Participating Affiliate; and

(2) St. Lawrence Gas Participants shall cease to be Plan Participants and thus shall not be entitled to receive any benefit payable under the Plan; and

(3) The liabilities of this Plan relating to the St. Lawrence Gas Participants shall be transferred to the SLG Buyer Supplemental Plan on or after the date of the SLG Closing and all of their benefits shall be fully provided under the SLG Buyer Supplemental Plan and not this Plan.

The SLG SPA provides that, effective as of the SLG Closing, St. Lawrence Gas Participants shall participate in the SLG Buyer Supplemental Plan which shall provide each St. Lawrence Gas Participant with accrued benefits that are no less than the accrued benefits with respect to each such person under the Plan as of the SLG Closing. Any benefits to be provided under the SLG Buyer Supplemental Plan will be governed by the terms and conditions of the SLG Buyer Supplemental Plan and not by this Plan to any extent.

As amended hereby, the Supplemental Plan is *hereby specifically ratified and reaffirmed in its entirety.*

To record this Fifth Amendment, the undersigned officers, pursuant to authorization of the Board of Directors of El, hereby confirm and execute the Fifth Amendment on this 28th day of October 2019.

By: /s/ Marc Weil
Marc Weil
Senior Vice President and
Chief Human Resources Officer Enbridge Inc.

By: /s/ Jim Haynes
Jim Haynes
Vice President of People and Operations, Human Resources
Pan Energy Services, LP

Exhibit 21.1 – Subsidiaries of the Registrant Enbridge Inc.

Entity Name	Jurisdiction
1090577 B.C. Unlimited Liability Company	British Columbia
1329165 Alberta Ltd.	Alberta
1682399 Ontario Corp.	Ontario
2099634 Ontario Limited	Ontario
2562961 Ontario Ltd.	Ontario
2193914 Canada Limited	Canada
4296559 Canada Inc.	Canada
3268126 Nova Scotia Company	Nova Scotia
5679 Cherry Lane, LLC	Wisconsin
626952 Alberta Ltd.	Alberta
627149 Saskatchewan Inc.	Saskatchewan
7243341 Canada Inc.	Canada
8056587 Canada Inc.	Canada
912176 Ontario Limited	Ontario
Alberta Saline Aquifer Project Inc.	Alberta
Alberta Solar One, Inc.	Alberta
Algonquin Gas Transmission, LLC	Delaware
Appaloosa Run Renewable Energy Project, LLC	Texas
Atlantis Offshore, LLC	Delaware
Bakken Pipeline Company LLC	Delaware
Bakken Pipeline Company LP	Delaware
Big Sandy Pipeline, LLC	Delaware
Blauracke GmbH	Germany
Brazoria Interconnector Gas Pipeline LLC	Delaware
Canyon Wind Farm, LLC	Delaware
Canyon Wind Farm II, LLC	Delaware
Canyon Wind Project, LLC	Texas
CCPS Transportation, LLC	Delaware
CCWF III, LLC	Texas
Cedar Point Wind, LLC	Delaware
Chapman Ranch Wind I, LLC	Delaware
Copiah Storage, LLC	Delaware
Cone Renewable Energy Project, LLC	Texas
Cruickshank Wind Farm Ltd.	Ontario
Deville Solar LLC	Delaware
Egan Hub Storage, LLC	Delaware
East Tennessee Natural Gas, LLC	Tennessee
Easter Renewable Energy Project, LLC	Texas
Eddystone Rail Company, LLC	Delaware
EFL Services (France) SAS	France
EIF US Holdings Inc.	Delaware
EIH S.à r.l.	Luxembourg

Eldorado Solar Power LLC	Delaware
Enbridge (Colombia) S.A.S.	Colombia
Enbridge (Gateway) Holdings Inc.	Canada
Enbridge (Houston Oil Terminal) LLC	Delaware
Enbridge (Ins) Holdings Inc.	Canada
Enbridge (Lux) Holdings Inc.	Alberta
Enbridge (Maritimes) Incorporated	Alberta
Enbridge (Rabaska) Holdings Inc.	Canada
Enbridge (Saskatchewan) Operating Services Inc.	Saskatchewan
Enbridge (SPOT) LLC	Delaware
Enbridge (U.S.) Inc.	Delaware
Enbridge Alliance (Canada) Management Inc.	Canada
Enbridge Alliance (U.S.) Management LLC	Delaware
Enbridge Athabasca Midstream Investor GP Inc.	Alberta
Enbridge Athabasca Midstream Investor Limited Partnership	Alberta
Enbridge Athabasca Midstream Trunkline GP Inc.	Alberta
Enbridge Athabasca Midstream Trunkline Limited Partnership	Alberta
Enbridge Atlantic (Holdings) Inc.	Canada
Enbridge Aux Sable (Canada) Management Inc.	Canada
Enbridge Aux Sable Holdings Inc.	Saskatchewan
Enbridge Aux Sable Products, Inc.	Delaware
Enbridge Aux Sable (U.S.) Management LLC	Delaware
Enbridge Bakken Pipeline Company Inc.	Canada
Enbridge Bakken Pipeline Limited Partnership	Alberta
Enbridge Blackspring Ridge I Wind Project GP Inc.	Alberta
Enbridge Blackspring Ridge I Wind Project Limited Partnership	Alberta
Enbridge Cactus II, LLC	Texas
Enbridge Canadian Renewable GP Inc.	Canada
Enbridge Canadian Renewable LP	Alberta
Enbridge CCS Holdings Inc.	Canada
Enbridge Commercial Services Inc.	Canada
Enbridge Commercial Trust	Alberta
Enbridge Emerging Technology Inc.	Canada
Enbridge Employee Services Canada Inc.	Canada
Enbridge Employee Services, Inc.	Delaware
Enbridge Energy Company, Inc.	Delaware
Enbridge Energy Distribution Inc.	Canada
Enbridge Energy, Limited Partnership	Delaware
Enbridge Energy Management, L.L.C.	Delaware
Enbridge Energy Partners, L.P.	Delaware
Enbridge Éolien France S.à r.l.	Luxembourg
Enbridge European Holdings S.à r.l	Luxembourg
Enbridge Finance (Barbados) Limited	Barbados
Enbridge Finance Company AG	Switzerland
Enbridge Finance Hungary Kft	Hungary

Enbridge Finance Luxembourg SA	Luxembourg
Enbridge Frontier Inc.	Canada
Enbridge Gas Inc.	Ontario
Enbridge GME, S. de R.L. de C.V.	Mexico
Enbridge GTM Canada Inc.	Canada
Enbridge Hardisty Storage Inc.	Alberta
Enbridge Holdings (Aux Sable Liquid Products) L.L.C.	Delaware
Enbridge Holdings (Aux Sable Midstream) L.L.C.	Delaware
Enbridge Holdings (Chapman Ranch) L.L.C.	Delaware
Enbridge Holdings (DakTex) L.L.C.	Delaware
Enbridge Holdings (Frontier) Inc.	Delaware
Enbridge Holdings (Grant Plains) L.L.C.	Delaware
Enbridge Holdings (Gray Oak) LLC	Delaware
Enbridge Holdings (Green Energy) L.L.C.	Delaware
Enbridge Holdings (IDR) L.L.C.	Delaware
Enbridge Holdings (LNG) L.L.C.	Delaware
Enbridge Holdings (Mississippi) L.L.C.	Delaware
Enbridge Holdings (Mustang) Inc.	Delaware
Enbridge Holdings (New Creek) L.L.C.	Delaware
Enbridge Holdings (New Energy) L.L.C.	Delaware
Enbridge Holdings (Offshore) L.L.C.	Delaware
Enbridge Holdings (Olympic) L.L.C.	Delaware
Enbridge Holdings (Plummer) L.L.C.	Delaware
Enbridge Holdings (Power) L.L.C.	Delaware
Enbridge Holdings (Seaway) L.L.C.	Delaware
Enbridge Holdings (Texas COLT) LLC	Delaware
Enbridge Holdings (Trunkline) L.L.C.	Delaware
Enbridge Holdings (U.S.) L.L.C.	Delaware
Enbridge Holdings (USGC) LLC	Delaware
Enbridge Hydropower Holdings Inc.	Canada
Enbridge Income Fund	Alberta
Enbridge Income Partners Holdings Inc.	Saskatchewan
Enbridge Ingleside, LLC	Delaware
Enbridge Ingleside Cactus II Holdings, LLC	Texas
Enbridge Ingleside Energy Center, LLC	Delaware
Enbridge Ingleside Holdings, LLC	Delaware
Enbridge Ingleside LPG Pipeline, LLC	Delaware
Enbridge Ingleside LPG Terminal, LLC	Delaware
Enbridge Ingleside Oil Pipeline, LLC	Delaware
Enbridge Ingleside Oil Terminal, LLC	Delaware
Enbridge Ingleside Operating, LLC	Delaware
Enbridge Ingleside Solar, L.L.C.	Delaware
Enbridge Ingleside Terminal Services, LLC	Delaware
Enbridge Insurance Bermuda Ltd.	Bermuda
Enbridge International Inc.	Canada

Enbridge Investment (Chapman Ranch) L.L.C.	Delaware
Enbridge Investment (Grant Plains) L.L.C.	Delaware
Enbridge Investment (New Creek) L.L.C.	Delaware
Enbridge Investment (Plummer) L.L.C.	Delaware
Enbridge Lac Alfred Wind Project GP Inc.	Canada
Enbridge Lac Alfred Wind Project Limited Partnership	Québec
Enbridge Luxembourg S.à r.l.	Luxembourg
Enbridge Management Services Inc.	Canada
Enbridge Massif du Sud Wind Project GP Inc.	Canada
Enbridge Massif du Sud Wind Project Limited Partnership	Québec
Enbridge Mexico Holdings Inc.	Canada
Enbridge Midstream Inc.	Alberta
Enbridge Midstream Operating, LLC	Delaware
Enbridge Offshore (Destin) L.L.C.	Delaware
Enbridge Offshore (Gas Gathering) L.L.C.	Delaware
Enbridge Offshore (Gas Transmission) L.L.C.	Delaware
Enbridge Offshore (Neptune Holdings) Inc.	Delaware
Enbridge Offshore Facilities, LLC	Delaware
Enbridge Offshore Pipelines, L.L.C.	Delaware
Enbridge Operating Services, L.L.C.	Delaware
Enbridge Operational Services Inc.	Canada
Enbridge Pipelines (Alberta Clipper) L.L.C.	Delaware
Enbridge Pipelines (Athabasca) GP Inc.	Alberta
Enbridge Pipelines (Athabasca) Inc.	Alberta
Enbridge Pipelines (Athabasca) Limited Partnership	Alberta
Enbridge Pipelines (Beaver Lodge) L.L.C.	Delaware
Enbridge Pipelines (Eastern Access) L.L.C.	Delaware
Enbridge Pipelines (FSP) L.L.C.	Delaware
Enbridge Pipelines (L3R) L.L.C.	Delaware
Enbridge Pipelines (Lakehead) L.L.C.	Delaware
Enbridge Pipelines (Mainline Expansion) L.L.C.	Delaware
Enbridge Pipelines (NW) Inc.	Canada
Enbridge Pipelines (Ozark) L.L.C.	Delaware
Enbridge Pipelines (Southern Lights) L.L.C.	Delaware
Enbridge Pipelines (Toledo) Inc.	Delaware
Enbridge Pipelines (Woodland) GP Inc.	Alberta
Enbridge Pipelines (Woodland) Limited Partnership	Alberta
Enbridge Pipelines Inc.	Canada
Enbridge Power Development Canada Inc.	Canada
Enbridge Power Operations Services Inc.	Canada
Enbridge Québec LNG Inc.	Canada
Enbridge Rail (Flanagan) L.L.C.	Delaware
Enbridge Rail (North Dakota) L.P.	Delaware
Enbridge Rail (Philadelphia) L.L.C.	Delaware
Enbridge Rampion UK Ltd	United Kingdom

Enbridge Rampion UK II Ltd	United Kingdom
Enbridge Renewable Energy Infrastructure Canada Inc.	Canada
Enbridge Renewable Energy Infrastructure Limited Partnership	Ontario
Enbridge Renewable Generation Inc.	Canada
Enbridge Renewable Holdings, L.L.C.	Delaware
Enbridge Renewable Infrastructure Development S.à r.l.	Luxembourg
Enbridge Renewable Infrastructure Holdings S.à r.l	Luxembourg
Enbridge Renewable Infrastructure Investments S.à r.l.	Luxembourg
Enbridge Renewable Investments, L.L.C.	Delaware
Enbridge Risk Management (U.S.) L.L.C.	Delaware
Enbridge Risk Management Inc.	Canada
Enbridge RNG (Sprout), LLC	Delaware
Enbridge Saint Robert Bellarmin Wind Project GP Inc.	Canada
Enbridge Saint Robert Bellarmin Wind Project Limited Partnership	Québec
Enbridge Services (CMO) L.L.C.	Delaware
Enbridge Services (Germany) GmbH	Germany
Enbridge SL Holdings LP	Alberta
Enbridge Solar (Adams), LLC	Delaware
Enbridge Solar (Cass Lake), LLC	Delaware
Enbridge Solar (Deer River), LLC	Delaware
Enbridge Solar (Flanagan), LLC	Delaware
Enbridge Solar (Floodwood), LLC	Delaware
Enbridge Solar (Plummer), LLC	Delaware
Enbridge Solar (Portage), LLC	Delaware
Enbridge Solar (Vesper), LLC	Delaware
Enbridge Southdown Inc.	Ontario
Enbridge Southern Lights GP Inc.	Canada
Enbridge Southern Lights LP	Alberta
Enbridge Storage (Cushing) L.L.C.	Delaware
Enbridge Storage (North Dakota) L.L.C.	Delaware
Enbridge Storage (Patoka) L.L.C.	Delaware
Enbridge Technology Inc.	Canada
Enbridge Thermal Energy Holdings Inc.	Canada
Enbridge Transmission Holdings (U.S.) L.L.C.	Delaware
Enbridge Transmission Holdings Inc.	Canada
Enbridge Transportation (IL-OK) L.L.C.	Delaware
Enbridge UK Holdings Ltd	United Kingdom
Enbridge US Holdings Inc.	Canada
Enbridge Wabamun Holdings Inc.	Alberta
Enbridge Wabamun Hub Ltd.	Alberta
Enbridge Wabamun Inc.	Alberta
Enbridge Wabamun North Inc.	Alberta
Enbridge Water Pipeline (Permian) L.L.C.	Delaware
Enbridge West Shore Holdings Inc.	Canada
Enbridge West Shore Inc.	Canada

Enbridge Western Access Inc.	Canada
Enbridge Wild Valley Holdings LLC	Delaware
Enbridge Wind Energy Inc.	Canada
Enbridge Wind Power General Partnership	Alberta
ERG Solar Limited Partnership	Alberta
Express Holdings (Canada) Limited Partnership	Manitoba
Express Holdings (USA), LLC	Delaware
Express Pipeline Limited Partnership	Alberta
Express Pipeline LLC	Delaware
Express Pipeline Ltd.	Canada
Flatland Solar, LLC	Texas
Flatland Solar Project, LLC	Delaware
Garden Banks Gas Pipeline, LLC	Delaware
Gazifère Inc.	Québec
Generation Pipeline LLC	Ohio
GLB Energy Management Inc.	Canada
Gray Oak Pipeline, LLC	Delaware
Great Lakes Basin Energy LP	Ontario
Greenwich Windfarm GP Inc.	New Brunswick
Greenwich Windfarm, LP	Ontario
Gulfstream Management and Operating Services, L.L.C.	Delaware
Gulfstream Natural Gas System, L.L.C.	Delaware
Hardisty Caverns Limited Partnership	Alberta
Hardisty Caverns Ltd.	Alberta
Highland Pipeline Leasing, LLC	Delaware
Honey Creek Solar, LLC	Delaware
Hoosier Line Wind, LLC	Delaware
Illinois Extension Pipeline Company, L.L.C.	Delaware
IPL AP Holdings (U.S.A.) Inc.	Delaware
IPL AP NGL Holdings (U.S.A.) Inc.	Delaware
IPL Energy (Atlantic) Incorporated	Alberta
IPL Energy (Colombia) Ltd.	Alberta
IPL Insurance (Barbados) Limited	Barbados
IPL System Inc.	Alberta
IPL Vector (U.S.A.) Inc.	Delaware
Islander East Pipeline Company, L.L.C.	Delaware
Keechi Holdings L.L.C.	Delaware
Keechi Wind, LLC	Delaware
Lakeside Performance Gas Services Ltd.	Canada
M&N Management Company, LLC	Delaware
M&N Operating Company, LLC	Delaware
Magicat Holdco, LLC	Delaware
Manta Ray Offshore Gathering Company, L.L.C.	Delaware
MarEn Bakken Company LLC	Delaware
Maritimes & Northeast Pipeline, L.L.C.	Delaware

Maritimes & Northeast Pipeline Limited Partnership	New Brunswick
Maritimes & Northeast Pipeline Management Ltd.	Canada
Market Hub Partners Canada L.P.	Ontario
Market Hub Partners Holding, LLC	Delaware
Market Hub Partners Management Inc.	Canada
MI Solar, LLC	Delaware
Midcoast Canada Operating Corporation	Alberta
Midcoast Energy Partners, L.P.	Delaware
Midcoast Holdings, L.L.C.	Delaware
Midcoast OLP GP, L.L.C.	Delaware
Mississippi Canyon Gas Pipeline, LLC	Delaware
MJ Asphalt Holdings Inc.	Saskatchewan
MJA Operations Ltd.	Saskatchewan
Moss Bluff Hub, LLC	Delaware
Nautilus Pipeline Company, L.L.C.	Delaware
Neptune Pipeline Company, L.L.C.	Delaware
New Creek Wind LLC	Delaware
NEXUS Capacity Services, ULC	British Columbia
Nexus Gas Transmission, LLC	Delaware
Niagara Gas Transmission Limited	Ontario
Niagara RNG GP Inc.	Ontario
North Dakota Pipeline Company LLC	Delaware
Northern Gateway Pipelines Inc.	Canada
Northern Gateway Pipelines Limited Partnership	Alberta
Oleoducto Al Pacifico SAS	Colombia
Ontario Excavac Inc.	Ontario
Ontario Sustainable Farms Inc.	Alberta
Pacific Trail Pipelines Management Inc.	British Columbia
Pacific Trail Pipelines Limited Partnership	British Columbia
PanEnergy Services, Limited Partnership	Louisiana
Platte Pipeline Company, LLC	Delaware
Pomelo Connector, LLC	Delaware
Port Barre Investments, LLC dba Bobcat Gas Storage	Delaware
Project AMBG2 Inc.	Ontario
Project AMBG2 LP	Ontario
Rio Bravo Pipeline Company, LLC	Texas
Sabal Trail Management, LLC	Delaware
Sabal Trail Transmission, LLC	Delaware
Saltville Gas Storage Company, L.L.C.	Virginia
Sarnia Airport Storage Pool Limited Partnership	Ontario
Sarnia Airport Storage Pool Management Inc.	Canada
SEHLP Management Inc.	Canada
SESH Capital, LLC	Delaware
SESH Sub Inc.	Delaware
Shannon Wind Energy, LLC	Delaware

Silver State Solar Power North, LLC	Delaware
South Texas Trail Pipeline, LLC	Delaware
Southeast Supply Header, LLC	Delaware
Southern Lights Holdings, L.L.C.	Delaware
Spectra Algonquin Holdings, LLC	Delaware
Spectra Algonquin Management, LLC	Delaware
Spectra Energy, LLC	Delaware
Spectra Energy Administrative Services, LLC	Delaware
Spectra Energy Aerial Patrol, LLC	Delaware
Spectra Energy Canada Call Co.	Nova Scotia
Spectra Energy Canada Exchangeco Inc.	Canada
Spectra Energy Canada Investments GP, ULC	British Columbia
Spectra Energy Canada Investments LP	Alberta
Spectra Energy Capital Funding, Inc.	Delaware
Spectra Energy Capital, LLC	Delaware
Spectra Energy County Line, LLC	Delaware
Spectra Energy Cross Border, LLC	Delaware
Spectra Energy DEFS Holding, LLC	Delaware
Spectra Energy DEFS Holding II, ULC	Delaware
Spectra Energy Empress Holding Limited Partnership	British Columbia
Spectra Energy Empress Management Holding ULC	British Columbia
Spectra Energy Express (Canada) Holding, ULC	Nova Scotia
Spectra Energy Express (US) Restructure Co., ULC	Nova Scotia
Spectra Energy Field Services Canada Holdings, LLC	Delaware
Spectra Energy Generation Pipeline Management, LLC	Delaware
Spectra Energy Holdings Co.	Nova Scotia
Spectra Energy Islander East Pipeline Company, L.L.C.	Delaware
Spectra Energy Liquids Projects GP Inc.	Canada
Spectra Energy Liquids Projects Limited Partnership	British Columbia
Spectra Energy LNG Sales, LLC	Delaware
Spectra Energy Midstream Holdco Management Partnership	Alberta
Spectra Energy Midstream Holdings Limited	Nova Scotia
Spectra Energy Midstream Holdings Limited Partnership	British Columbia
Spectra Energy Midwest Liquids Pipeline, LLC	Delaware
Spectra Energy MNEP Holdings Limited Partnership	British Columbia
Spectra Energy Nexus Management, LLC	Delaware
Spectra Energy Nova Scotia Holdings Co.	Nova Scotia
Spectra Energy Operating Company, LLC	Delaware
Spectra Energy Partners Atlantic Region Newco, LLC	Delaware
Spectra Energy Partners Canada Holding, S.à r.l.	Luxembourg
Spectra Energy Partners (DE) GP, LP	Delaware
Spectra Energy Partners GP, LLC	Delaware
Spectra Energy Partners, LP	Delaware
Spectra Energy Partners Sabal Trail Transmission, LLC	Delaware
Spectra Energy Services, LLC	Delaware

Spectra Energy Southeast Services, LLC	Delaware
Spectra Energy Southeast Supply Header, LLC	Delaware
Spectra Energy Transmission, LLC	Delaware
Spectra Energy Transmission II, LLC	Delaware
Spectra Energy Transmission Resources, LLC	Delaware
Spectra Energy Transmission Services, LLC	Delaware
Spectra Energy Transport & Trading Company, LLC	Colorado
Spectra Energy U.S.-Canada Finance GP, ULC	British Columbia
Spectra Energy U.S.-Canada Finance, LP	Delaware
Spectra Energy VCP Holdings, LLC	Delaware
Spectra Energy Westheimer, LLC	Delaware
Spectra Nexus Gas Transmission, LLC	Delaware
St. Clair Pipelines L.P.	Ontario
St. Clair Pipelines Management Inc.	Canada
Steckman Ridge GP, LLC	Delaware
Steckman Ridge, LP	Delaware
Sugar Loaf Renewable Energy Project, LLC	Delaware
Sunwest Heartland Terminals Ltd.	Alberta
Superior Oil Limited	Saskatchewan
Talbot Windfarm GP Inc.	New Brunswick
Talbot Windfarm, LP	Ontario
Texas COLT LLC	Delaware
Texas Eastern Communications, LLC	Delaware
Texas Eastern Terminal Co, LLC	Delaware
Texas Eastern Transmission, LP	Delaware
TGE Colorado 224, LLC	Delaware
TGE Idaho 221, LLC	Delaware
TGE Illinois 181, LLC	Delaware
TGE Illinois 211, LLC	Delaware
TGE Illinois 226, LLC	Delaware
TGE Indiana 191, LLC	Delaware
TGE Indiana 192, LLC	Delaware
TGE Nevada 223, LLC	Delaware
TGE Pennsylvania 203, LLC	Delaware
TGE Texas 213, LLC	Delaware
TGE Virginia 195, LLC	Delaware
TGE Wyoming 212, LLC	Delaware
TGE Wyoming 222, LLC	Delaware
TGE Wyoming 225, LLC	Delaware
The Ottawa Gas Company Inc.	Canada
Tidal Energy Marketing (U.S.) L.L.C.	Delaware
Tidal Energy Marketing Inc.	Canada
Tilbury Solar Project LP	Ontario
Tri Global Energy, LLC	Delaware
Tri Global Holdings, LLC	Delaware

Tri-State Holdings, LLC	Michigan
UEI Holdings (New Brunswick) Inc.	Canada
Union Energy Solutions Limited Partnership	British Columbia
Valley Crossing Pipeline, LLC	Delaware
Vector Pipeline Holdings Ltd.	Canada
Vector Pipeline L.P.	Delaware
Vector Pipeline Limited	Canada
Vector Pipeline Limited Partnership	Alberta
Vector Pipeline, LLC	Delaware
Vermilion Grove Wind, LLC	Delaware
Water Valley Wind Energy, LLC	Texas
Westcoast Connector Gas Transmission Ltd.	British Columbia
Westcoast Energy Inc.	Canada
Westcoast Energy (U.S.) LLC	Delaware
Westcoast Energy Ventures Inc.	Canada
Whitetail Gas-Fired Peaking Project GP Inc.	Alberta
Whitetail Gas-Fired Peaking Project Limited Partnership	Alberta
Whitetail Gas-Fired Peaking Project Ltd.	Alberta
Woodford Wind Holding, LLC	Delaware
Wrangler Pipeline, L.L.C.	Delaware

Exhibit 22.1

Subsidiary Guarantors

As of December 31, 2022, each of the following subsidiaries of Enbridge Inc. ("Enbridge"), both of which are indirect, wholly-owned subsidiaries of Enbridge, has fully and unconditionally guaranteed on an unsecured, joint and several basis, each of the registered debt securities of the Company listed below:

Subsidiary Guarantors

1. Spectra Energy Partners, LP, a Delaware limited partnership
2. Enbridge Energy Partners, L.P., a Delaware limited partnership

Registered Debt Securities of Enbridge Guaranteed by each of the Subsidiary Guarantors

1. Floating Rate Senior Notes due 2023
2. 0.550% Senior Notes due 2023
3. 4.000% Senior Notes due 2023
4. Floating Rate Senior Notes due 2024
5. 3.500% Senior Notes due 2024
6. 2.150% Senior Notes due 2024
7. 2.500% Senior Notes due 2025
8. 2.500% Senior Notes due 2025
9. 4.250% Senior Notes due 2026
10. 1.600% Senior Notes due 2026
11. 3.700% Senior Notes due 2027
12. 3.125% Senior Notes due 2029
13. 2.500% Sustainability-Linked Senior Notes due 2033
14. 4.500% Senior Notes due 2044
15. 5.500% Senior Notes due 2046
16. 4.000% Senior Notes due 2049
17. 3.400% Senior Notes due 2051

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the registration statements on Form S-3 (File Nos. 333-231553, 333-266405) and S-8 (File Nos. 333-250121, 333-231435, 333-145236, 333-127265, 333-13456, 333-97305, and 333-216272) of Enbridge Inc. of our report dated February 10, 2023 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Canada

February 10, 2023

EXHIBIT 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Gregory L. Ebel, certify that:

1. I have reviewed this annual report on Form 10-K of Enbridge Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting

Date: February 10, 2023

By: **/s/ Gregory L. Ebel**

Gregory L. Ebel
President and Chief Executive Officer
(Principal Executive Officer)
Enbridge Inc.

EXHIBIT 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Vern D. Yu, certify that:

1. I have reviewed this annual report on Form 10-K of Enbridge Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting

Date: February 10, 2023

By: **/s/ Vern D. Yu**

Vern D. Yu
Executive Vice President, Corporate Development, Chief Financial Officer and President, New Energy Technologies
(Principal Financial Officer)
Enbridge Inc.

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Enbridge Inc. on Form 10-K for the period ending December 31, 2022 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Gregory L. Ebel, President and Chief Executive Officer of Enbridge Inc., certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Enbridge Inc.

Date: February 10, 2023

By: **/s/ Gregory L. Ebel**

Gregory L. Ebel
President and Chief Executive Officer
(Principal Executive Officer)
Enbridge Inc.

EXHIBIT 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Enbridge Inc. on Form 10-K for the period ending December 31, 2022 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Vern D. Yu, Executive Vice President, Corporate Development, Chief Financial Officer and President, New Energy Technologies of Enbridge Inc., certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Enbridge Inc.

Date: February 10, 2023

By: **/s/ Vern D. Yu**

Vern D. Yu
Executive Vice President, Corporate Development, Chief Financial Officer and President, New Energy Technologies
(Principal Financial Officer)
Enbridge Inc.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit 1, Tab 8

Question(s):

a) Please update the evidence in Tab 8 to include the audited consolidated financial statements for 2022 (similar to Attachment 2) when they are available, including a reconciliation of audited EGI income (per financial statements) to corporate income for utility income determination purposes EGI utility income actual results (similar to Attachments 6 & 7), and the Annua Report and Management Discussion and Analysis (MD&A) for the most recent year from the Parent Company (similar to Attachment 10).

b) Please provide any rating agency reports that are more recent than those noted in the evidence.

c) Please provide the most recent Short Form Base Shelf Prospectus, if more recent than September 8, 2021.

d) Please provide the 2022 federal and provincial tax returns (similar to Attachment 14) when they become available.

Response:

a) Please see response at Exhibit I.1.8-STAFF-14 part b) ii) for the 2022 Enbridge Gas Inc. Audited Consolidated Financial Statements and Exhibit I.1.8-CME-7 part a) for the 2022 Enbridge Inc. Annual Report. The reconciliations of audited Enbridge Gas income (per financial statements) to corporate income for utility income determination purposes Enbridge Gas utility income actual results are provided at Attachment 1 and Attachment 2.

b) Please see response at Exhibit I.1.8-STAFF-14 part b) iv).

c) The Short Form Base Shelf Prospectus, dated September 8, 2021, provided at Exhibit 1, Tab 8, Schedule 1, Attachment 13 is the most recent available.

d) The 2022 federal and provincial tax returns will be available in June 2023.

RECONCILIATION OF AUDITED EGI INCOME (PER FINANCIAL STATEMENTS)
TO CORPORATE INCOME FOR UTILITY INCOME DETERMINATION PURPOSES
2022 ACTUAL

Line no.	($ millions)	Col. 1 Audited Income (as per Financial Statements)	Col. 2 Corporate Income (as per Utility Income Schedule)	Col. 3 Variance	Col. 4 Reference
	Operating Revenues				
1.	Gas sales and distribution	5,613.7	6,198.6		
2.	Storage, transportation and other	994.5	-		
3.	Transportation	-	146.2		
4.	Storage	-	179.4		
5.	Other operating revenue	-	71.8		
6.	Other Income	79.2	13.0		
7.	Total operating revenue	6,687.4	6,609.0	(78.4)	(a)
	Operating Expenses				
8.	Gas Costs	3,678.6	3,678.6	0.0	
9.	Operation and maintenance	1,226.9	1,028.0	(198.9)	(b)
10.	Depreciation and amortization expense	690.1	690.1	(0.0)	
11.	Fixed financing costs	-	3.5	3.5	(c)
12.	Municipal and other taxes	-	120.4	120.4	(d)
13.	Cost of service	5,595.6	5,520.6	(75.0)	
14.	Income before interest and income taxes	1,091.8	1,088.4	(3.4)	
15.	Interest and financing expenses	423.1	-	(423.1)	(e)
16.	Income before income taxes	668.7	1,088.4	419.7	
17.	Income taxes	68.6	-	(68.6)	(f)
18.	Net Income	600.1	1,088.4	488.3	

a)	**Audited Total Operating Revenue**	6,687.4
	Reclassify pension related other revenue to O&M	(66.6)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other r	(12.2)
	Reclassify other expenses out of other income to O&M	0.4
	Corporate Total Operating Revenue	6,609.0
b)	**Audited Operation and Maintenance**	1,226.9
	Reclassify pension related other revenue to O&M	(66.6)
	Reclassify Municipal & Property Taxes out of O&M	(120.4)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other r	(12.2)
	Reclassify other expenses out of other income to O&M	0.4
	Corporate Operation and Maintenance	1,028.0
c)	**Audited Fixed Financing Costs**	-
	Reclassify fixed financing costs from interest and financing expenses	3.5
	Corporate Fixed Financing Costs	3.5
d)	**Audited Municipal and Other Taxes**	-
	Reclassify Municipal and other taxes included within O&M costs	120.4
	Corporate Municipal and Other Taxes	120.4
e)	**Audited Interest and Financing expenses**	423.1
	Reclassify fixed financing costs from interest and financing expenses	(3.5)
	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure	(419.6)
	Corporate Interest and Financing expenses	0.0
f)	**Audited Income Taxes**	68.6
	Elimination of corporate income taxes which will be calculated on a utility stand-alone basis	(68.6)
	Corporate Income Taxes	-

RECONCILIATION OF CORPORATE INCOME
TO UTILITY INCOME
2022 ACTUAL

Line no.	($ millions)	Col. 1 Corporate Income (as per Utility Income Schedule)	Col. 2 Utility Income (as per Utility Income Schedule)	Col. 3 Variance	Col. 4 Reference
	Operating Revenues				
1.	Gas sales and distribution	6,198.6	6,164.5	(34.1)	(a)
2.	Storage, transportation and other	-	-	-	
3.	Transportation	146.2	145.7	(0.5)	(b)
4.	Storage	179.4	6.9	(172.5)	(c)
5.	Other operating revenue	71.8	53.6	(18.2)	(d)
6.	Other Income	13.0	(2.1)	(15.1)	(e)
7.	Total operating revenue	6,609.0	6,368.6	(240.4)	
	Operating Expenses				
8.	Gas Costs	3,678.6	3,630.3	(48.3)	(f)
9.	Operation and maintenance	1,028.0	1,002.6	(25.4)	(g)
10.	Depreciation and amortization expense	690.1	653.1	(37.0)	(h)
11.	Fixed financing costs	3.5	4.6	1.1	(i)
12.	Municipal and other taxes	120.4	118.5	(1.9)	(j)
13.	Cost of service	5,520.6	5,409.0	(111.6)	
14.	Income before interest and income taxes	1,088.4	959.6	(128.8)	
15.	Interest and financing expenses	-	-	-	
16.	Income before income taxes	1,088.4	959.6	(128.8)	
17.	Income taxes	-	38.0	38.0	(k)
18.	Net Income	1,088.4	921.6	(166.8)	

a)	**Corporate Gas Sales and Distribution Revenue**	6,198.6
	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(16.6)
	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(17.4)
	Utility Gas Sales and Distribution Revenue	6,164.5
b)	**Corporate Transportation Revenue**	146.2
	Elimination of unregulated storage	0.3
	Elimination of the Union rate zone shareholder portion of net optimization activity (before tax)	(0.9)
	Utility Transportation Revenue	145.7
c)	**Corporate Transportation Revenue**	179.4
	Elimination of unregulated storage	(172.4)
	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before	(0.1)
	Utility Transportation Revenue	6.9
d)	**Corporate Other Operating Revenue**	71.8
	Elimination of unregulated storage	(2.3)
	Adjust EGD rate zone OBA costs to reflect approved unit costs agreed to be used for determining	(4.8)
	Elimination of EGD rate zone Open Bill shareholder incentive	0.3
	Elimination of EGD rate zone shareholder portion of transactional service revenues	(4.8)
	Elimination of demand-side management incentive	(5.8)
	Elimination of EGD rate zone net revenue from ABC T-service, considered to be non-utility	(0.7)
	Utility Other Operating Revenue	53.6
e)	**Corporate Other Income**	13.0
	Elimination of unregulated storage	(0.1)
	Elimination of interest income from investments not included in utility rate base	(0.1)
	Elimination of interest income from affiliates	(3.4)
	Elimination of Part VI.1 tax	(11.5)
	Utility Other Income	(2.1)
f)	**Corporate Gas Costs**	3,678.6
	Elimination of unregulated storage	(31.7)
	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(16.6)
	Utility Gas Costs	3,630.3
g)	**Corporate Operation and Maintenance**	1,028.0
	Elimination of unregulated storage	(21.6)
	Elimination of donations	(1.1)
	Elimination of OEB Penalty assessed in EB-2021-0204 (Assurance of Voluntary Compliance and	(0.3)
	Adjust unregulated storage back to legacy methodology instead of harmonized amount	6.0
	Eliminate CFCAM charges (prelim amt)	(8.4)
	Utility Operation and Maintenance	1,002.6
h)	**Corporate Depreciation and Amortization Expense**	690.1
	Elimination of unregulated storage	(14.5)
	Eliminate amortization of PPD (purchase price discrepancy)	(22.5)
	Utility Depreciation and Amortization Expense	653.1
i)	**Corporate Fixed Financing Costs**	3.5
	Interest on security deposits held during the year and included in elimination of corporate interest	1.1
	Utility Fixed Financing Costs	4.6
j)	**Corporate Municipal and Other Taxes**	120.4
	Elimination of unregulated storage	(1.9)
	Utility Municipal and Other Taxes	118.5
k)	**Corporate Income Taxes**	-
	Utility Income Taxes calculated based on total utility income	38.0
	Utility Income Taxes	38.0

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-8-1

Question(s):

Please provide in a single table, for each year between 2013 and 2022, the annual ESM calculations for Enbridge (or EGD and Union as would have been the case before the amalgamation) in the same format as is provided in Enbridge's annual ESM/DVA disposition application.

Response:

Please see Attachment 1 for tables showing the annual ESM calculations for Enbridge Gas from 2019 to 2022 as well as separate tables for both EGD and Union for the years 2013 to 2018.

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2013

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		321.2
3	Less: Income Taxes		25.8
4	Utility Income		295.4
5	Utility Rate Base		3,783.9
6	Indicated Return on Rate Base %	(line 4 / line 5)	7.81%
7	Less: Required Rate of Return %		7.18%
8	(Deficiency) / Sufficiency %		0.63%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	23.7
10	Provision for Income Taxes		8.5
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	32.2
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		321.2
14	Less: Long Term Debt Costs		147.4
15	Less: Short Term Debt Costs		0.7
16	Less: Preference Share Costs		2.1
17	Net Income before Income Taxes		171.1
18	Less: Income Taxes		25.8
19	Net Income Applicable to Common Equity	(line 16 - line 17)	145.3
20	Common Equity		1,362.2
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	8.93%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	10.67%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.74%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	23.7
25	Provision for Income Taxes		8.5
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	32.2

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2013

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		355.0
3	Less: Income Taxes		48.2
4	Utility Income		306.8
5	Utility Rate Base		4,293.2
6	Indicated Return on Rate Base %	(line 4 / line 5)	7.15%
7	Less: Required Rate of Return %		6.61%
8	(Deficiency) / Sufficiency %		0.53%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	22.9
10	Provision for Income Taxes		8.3
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	31.2
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		355.0
14	Less: Long Term Debt Costs		140.8
15	Less: Short Term Debt Costs		2.6
16	Less: Preference Share Costs		2.4
17	Net Income before Income Taxes		209.2
18	Less: Income Taxes		48.2
19	Net Income Applicable to Common Equity	(line 16 - line 17)	161.0
20	Common Equity		1,545.6
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	8.93%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	10.41%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.48%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	22.9
25	Provision for Income Taxes		8.3
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	31.2

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2014

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		330.6
3	Less: Income Taxes		24.1
4	Utility Income		306.5
5	Utility Rate Base		3,976.4
6	Indicated Return on Rate Base %	(line 4 / line 5)	7.71%
7	Less: Required Rate of Return %		7.42%
8	(Deficiency) / Sufficiency %		0.28%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	11.3
10	Provision for Income Taxes		4.1
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	15.4
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		330.6
14	Less: Long Term Debt Costs		151.0
15	Less: Short Term Debt Costs		-0.7
16	Less: Preference Share Costs		2.8
17	Net Income before Income Taxes		177.6
18	Less: Income Taxes		24.1
19	Net Income Applicable to Common Equity	(line 16 - line 17)	153.5
20	Common Equity		1,431.5
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	9.93%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	10.72%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		0.79%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	11.3
25	Provision for Income Taxes		4.1
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	15.4

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2014

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		334.7
3	Less: Income Taxes		6.1
4	Utility Income		328.6
5	Utility Rate Base		4,701.3
6	Indicated Return on Rate Base %	(line 4 / line 5)	6.99%
7	Less: Required Rate of Return %		6.59%
8	(Deficiency) / Sufficiency %		0.40%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	18.6
10	Provision for Income Taxes		6.7
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	25.3
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		334.7
14	Less: Long Term Debt Costs		146.4
15	Less: Short Term Debt Costs		2.8
16	Less: Preference Share Costs		2.4
17	Net Income before Income Taxes		183.1
18	Less: Income Taxes		6.1
19	Net Income Applicable to Common Equity	(line 16 - line 17)	177.0
20	Common Equity		1,692.5
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	9.36%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	10.46%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.10%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	18.6
25	Provision for Income Taxes		6.7
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	25.3

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2015

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		322.7
3	Less: Income Taxes		15.7
4	Utility Income		307.0
5	Utility Rate Base		4,228.4
6	Indicated Return on Rate Base %	(line 4 / line 5)	7.26%
7	Less: Required Rate of Return %		7.27%
8	(Deficiency) / Sufficiency %		-0.01%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(0.6)
10	Provision for Income Taxes		(0.2)
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(0.8)
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		322.7
14	Less: Long Term Debt Costs		155.0
15	Less: Short Term Debt Costs		-1.2
16	Less: Preference Share Costs		2.7
17	Net Income before Income Taxes		166.2
18	Less: Income Taxes		15.7
19	Net Income Applicable to Common Equity	(line 16 - line 17)	150.6
20	Common Equity		1,522.2
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	9.93%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	9.89%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		-0.04%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	(0.6)
25	Provision for Income Taxes		(0.2)
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	(0.8)

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2015

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		357.3
3	Less: Income Taxes		19.4
4	Utility Income		337.9
5	Utility Rate Base		5,079.8
6	Indicated Return on Rate Base %	(line 4 / line 5)	6.65%
7	Less: Required Rate of Return %		6.47%
8	(Deficiency) / Sufficiency %		0.19%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	9.5
10	Provision for Income Taxes		3.4
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	12.9
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		357.3
14	Less: Long Term Debt Costs		153.9
15	Less: Short Term Debt Costs		2.2
16	Less: Preference Share Costs		2.2
17	Net Income before Income Taxes		199.0
18	Less: Income Taxes		19.4
19	Net Income Applicable to Common Equity	(line 16 - line 17)	179.6
20	Common Equity		1,828.7
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	9.30%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	9.82%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		0.52%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	9.5
25	Provision for Income Taxes		3.4
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	12.9

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2016

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		325.4
3	Less: Income Taxes		4.4
4	Utility Income		321.0
5	Utility Rate Base		4,758.4
6	Indicated Return on Rate Base %	(line 4 / line 5)	6.75%
7	Less: Required Rate of Return %		6.99%
8	(Deficiency) / Sufficiency %		-0.25%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(11.7)
10	Provision for Income Taxes		(4.2)
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(16.0)
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		325.4
14	Less: Long Term Debt Costs		161.8
15	Less: Short Term Debt Costs		-1.8
16	Less: Preference Share Costs		2.6
17	Net Income before Income Taxes		162.7
18	Less: Income Taxes		4.4
19	Net Income Applicable to Common Equity	(line 16 - line 17)	158.3
20	Common Equity		1,713.0
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	9.93%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	9.24%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		-0.69%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	(11.8)
25	Provision for Income Taxes		(4.2)
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	(16.0)

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2016

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		394.6
3	Less: Income Taxes		17.3
4	Utility Income		377.3
5	Utility Rate Base		5,909.0
6	Indicated Return on Rate Base %	(line 4 / line 5)	6.39%
7	Less: Required Rate of Return %		6.30%
8	(Deficiency) / Sufficiency %		0.08%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	5.0
10	Provision for Income Taxes		1.8
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	6.8
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		394.6
14	Less: Long Term Debt Costs		171.9
15	Less: Short Term Debt Costs		2.8
16	Less: Preference Share Costs		2.2
17	Net Income before Income Taxes		217.8
18	Less: Income Taxes		17.3
19	Net Income Applicable to Common Equity	(line 16 - line 17)	200.5
20	Common Equity		2,127.2
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	9.19%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	9.42%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		0.23%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	5.0
25	Provision for Income Taxes		1.8
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	6.8

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2017

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		344.3
3	Less: Income Taxes		(5.0)
4	Utility Income		349.3
5	Utility Rate Base		5,473.9
6	Indicated Return on Rate Base %	(line 4 / line 5)	6.38%
7	Less: Required Rate of Return %		6.66%
8	(Deficiency) / Sufficiency %		-0.28%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(15.2)
10	Provision for Income Taxes		(5.5)
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(20.7)
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		344.3
14	Less: Long Term Debt Costs		165.3
15	Less: Short Term Debt Costs		0.8
16	Less: Preference Share Costs		2.8
17	Net Income before Income Taxes		175.4
18	Less: Income Taxes		(5.0)
19	Net Income Applicable to Common Equity	(line 16 - line 17)	180.4
20	Common Equity		1,970.6
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	9.93%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	9.16%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		-0.77%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	(15.2)
25	Provision for Income Taxes		(5.5)
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	(20.7)

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2017

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		424.8
3	Less: Income Taxes		1.0
4	Utility Income		423.8
5	Utility Rate Base		6,465.2
6	Indicated Return on Rate Base %	(line 4 / line 5)	6.55%
7	Less: Required Rate of Return %		6.02%
8	(Deficiency) / Sufficiency %		0.54%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	34.6
10	Provision for Income Taxes		12.5
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	47.1
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		424.8
14	Less: Long Term Debt Costs		178.7
15	Less: Short Term Debt Costs		3.8
16	Less: Preference Share Costs		2.3
17	Net Income before Income Taxes		239.9
18	Less: Income Taxes		1.0
19	Net Income Applicable to Common Equity	(line 16 - line 17)	238.9
20	Common Equity		2,327.5
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	8.78%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	10.27%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.49%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	34.6
25	Provision for Income Taxes		12.5
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	47.1

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2018

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		370.2
3	Less: Income Taxes		(6.0)
4	Utility Income		376.2
5	Utility Rate Base		6,018.4
6	Indicated Return on Rate Base %	(line 4 / line 5)	6.25%
7	Less: Required Rate of Return %		6.36%
8	(Deficiency) / Sufficiency %		-0.10%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(6.3)
10	Provision for Income Taxes		(2.3)
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(8.5)
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		370.2
14	Less: Long Term Debt Costs		161.2
15	Less: Short Term Debt Costs		3.2
16	Less: Preference Share Costs		2.9
17	Net Income before Income Taxes		202.9
18	Less: Income Taxes		(6.0)
19	Net Income Applicable to Common Equity	(line 16 - line 17)	208.9
20	Common Equity		2,166.6
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	9.93%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	9.64%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		-0.29%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	(6.2)
25	Provision for Income Taxes		(2.2)
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	(8.5)

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2018

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		489.9
3	Less: Income Taxes		38.5
4	Utility Income		451.4
5	Utility Rate Base		6,729.2
6	Indicated Return on Rate Base %	(line 4 / line 5)	6.71%
7	Less: Required Rate of Return %		6.07%
8	(Deficiency) / Sufficiency %		0.64%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	42.7
10	Provision for Income Taxes		15.4
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	58.1
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		489.9
14	Less: Long Term Debt Costs		181.2
15	Less: Short Term Debt Costs		6.9
16	Less: Preference Share Costs		2.6
17	Net Income before Income Taxes		299.2
18	Less: Income Taxes		38.5
19	Net Income Applicable to Common Equity	(line 16 - line 17)	260.7
20	Common Equity		2,422.5
21	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	9.00%
22	Achieved Rate of Return on Equity %	(line 18 / line 19)	10.76%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.76%
24	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	42.7
25	Provision for Income Taxes		15.4
26	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	58.1

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2019

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		919.7
3	Less: Income Taxes		59.9
4	Utility Income		859.9
5	Utility Rate Base		13,139.0
6	Indicated Return on Rate Base %	(line 4 / line 5)	6.54%
7	Less: Required Rate of Return %		6.55%
8	(Deficiency) / Sufficiency %		0.00%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(0.3)
10	Provision for Income Taxes		(0.1)
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(0.3)
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		919.7
14	Less: Long Term Debt Costs		356.1
15	Less: Short Term Debt Costs		8.3
16	Net Income before Income Taxes		555.3
17	Less: Income Taxes		59.9
18	Net Income Applicable to Common Equity	(line 16 - line 17)	495.5
19	Common Equity		4,730.0
20	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	10.48%
21	Achieved Rate of Return on Equity %	(line 18 / line 19)	10.47%
22	Resulting (Deficiency) / Sufficiency in Return on Equity %		-0.01%
23	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	(0.3)
24	Provision for Income Taxes		(0.1)
25	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	(0.3)

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2020

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		841.1
3	Less: Income Taxes		39.2
4	Utility Income		801.9
5	Utility Rate Base		13,562.0
6	Indicated Return on Rate Base %	(line 4 / line 5)	5.91%
7	Less: Required Rate of Return %		6.38%
8	(Deficiency) / Sufficiency %		-0.47%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(63.6)
10	Provision for Income Taxes		(22.9)
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(86.5)
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		841.1
14	Less: Long Term Debt Costs		375.3
15	Less: Short Term Debt Costs		1.0
16	Net Income before Income Taxes		464.8
17	Less: Income Taxes		39.2
18	Net Income Applicable to Common Equity	(line 16 - line 17)	425.6
19	Common Equity		4,882.3
20	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	10.02%
21	Achieved Rate of Return on Equity %	(line 18 / line 19)	8.72%
22	Resulting (Deficiency) / Sufficiency in Return on Equity %		-1.30%
23	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	(63.6)
24	Provision for Income Taxes		(22.9)
25	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	(86.5)

STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THEYEAR ENDED DECEMBER 31, 2021

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		884.3
3	Less: Income Taxes		41.8
4	Utility Income		842.5
5	Utility Rate Base		14,221.6
6	Indicated Return on Rate Base %	(line 4 / line 5)	5.92%
7	Less: Required Rate of Return %		6.17%
8	(Deficiency) / Sufficiency %		-0.24%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(34.4)
10	Provision for Income Taxes		(12.4)
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(46.8)
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		884.3
14	Less: Long Term Debt Costs		371.3
15	Less: Short Term Debt Costs		1.9
16	Net Income before Income Taxes		511.1
17	Less: Income Taxes		41.8
18	Net Income Applicable to Common Equity	(line 16 - line 17)	469.4
19	Common Equity		5,119.8
20	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	9.84%
21	Achieved Rate of Return on Equity %	(line 18 / line 19)	9.17%
22	Resulting (Deficiency) / Sufficiency in Return on Equity %		-0.67%
23	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	(34.4)
24	Provision for Income Taxes		(12.4)
25	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	(46.8)

STATEMENT OF UTILITY
PRELIMINARY RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE YEAR ENDED DECEMBER 31, 2022

Line No.	Particulars ($ millions / %)		
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax		959.6
3	Less: Income Taxes		38.0
4	Utility Income		921.6
5	Utility Rate Base		15,381.3
6	Indicated Return on Rate Base %	(line 4 / line 5)	5.99%
7	Less: Required Rate of Return %		6.28%
8	(Deficiency) / Sufficiency %		-0.29%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(44.3)
10	Provision for Income Taxes		(16.0)
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(60.2)
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax		959.6
14	Less: Long Term Debt Costs		384.9
15	Less: Short Term Debt Costs		18.4
16	Net Income before Income Taxes		556.3
17	Less: Income Taxes		38.0
18	Net Income Applicable to Common Equity	(line 16 - line 17)	518.3
19	Common Equity		5,537.3
20	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	10.16%
21	Achieved Rate of Return on Equity %	(line 18 / line 19)	9.36%
22	Resulting (Deficiency) / Sufficiency in Return on Equity %		-0.80%
23	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	(44.3)
24	Provision for Income Taxes		(16.0)
25	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	(60.2)

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-8-1, Attachment 4

Question(s):

For each year between 2013 and 2018, and for 2022, please provide a similar table of annual actual utility income, for Enbridge's (or EGD and Union as would have been the case before the amalgamation).

Response:

Please see Attachment 1 for tables showing annual actual utility income for both EGD and Union for the years 2013 through 2018 as well as Enbridge Gas preliminary actuals for 2022.

UGL UTILITY INCOME
2013 ACTUAL

Line No.	Particulars ($ millions)	Corporate (a)	Storage Unregulated Storage (b)	Adjustments (c)		Income Utility Income (d) =(a)-(b)+(c)
1	Gas sales and distribution	1,621.0	-	(15.7)	(1)	1,605.3
2	Transportation	161.2	(0.4)	(1.4)	(2)	160.1
3	Storage	90.7	81.8	-		8.8
4	Other operating revenue	27.3	-	(9.2)	(3)	18.0
5	Other income	(2.9)	(1.9)	0.4	(4)	(0.6)
6	Total operating revenue	1,897.3	79.5	(25.9)		1,791.6
7	Gas costs	848.9	2.9	(15.7)	(5)	830.3
8	Operation and maintenance	397.3	13.3	(3.0)	(6)	381.0
9	Depreciation and amortization expense	202.7	9.7	-		193.0
10	Fixed financing costs	-	-	0.4	(7)	0.4
11	Municipal and other taxes	65.3	1.4	-		63.8
12	Cost of service	1,514.2	27.3	(18.3)		1,468.5
13	Utility income before income taxes					323.2
14	Income tax expense					25.8
15	Utility income					297.4

UGL UTILITY INCOME
2014 ACTUAL

Line No.	Particulars ($ millions)	Corporate	Storage Unregulated Storage	Adjustments		Income Utility Income
		(a)	(b)	(c)		(d) =(a)-(b)+(c)
1	Gas sales and distribution	1,778.5	-	(17.0)	(1)	1,761.5
2	Transportation	183.4	(0.4)	(32.4)	(2)	151.4
3	Storage	82.3	74.5	-		7.8
4	Other operating revenue	21.2	-	(6.3)	(3)	14.9
5	Other income	(4.1)	(2.4)	0.6	(4)	(1.1)
6	Total operating revenue	2,061.3	71.7	(55.1)		1,934.5
7	Gas costs	977.2	1.7	(17.0)	(5)	958.5
8	Operation and maintenance	396.9	14.0	(3.6)	(6)	379.3
9	Depreciation and amortization expense	210.6	10.3	-		200.4
10	Fixed financing costs	-	-	0.7	(7)	0.7
11	Municipal and other taxes	65.8	1.5	-		64.3
12	Cost of service	1,650.5	27.4	(19.9)		1,603.2
13	Utility income before income taxes					331.3
14	Income tax expense					24.1
15	Utility income					307.1

UGL UTILITY INCOME
2015 ACTUAL

Line No.	Particulars ($ millions)	Corporate	Storage Unregulated Storage	Adjustments		Income Utility Income
		(a)	(b)	(c)		(d) =(a)-(b)+(c)
1	Gas sales and distribution	1,674.8	-	(15.6)	(1)	1,659.2
2	Transportation	155.8	(0.5)	-		156.2
3	Storage	83.2	75.8	-		7.4
4	Other operating revenue	25.8	-	(5.9)	(2)	19.9
5	Other income	(2.3)	(0.7)	1.2	(3)	(0.4)
6	Total operating revenue	1,937.3	74.6	(20.3)		1,842.3
7	Gas costs	874.6	2.2	(15.6)	(4)	856.8
8	Operation and maintenance	399.1	14.8	(1.3)	(5)	383.0
9	Depreciation and amortization expense	223.8	11.6	-		212.2
10	Fixed financing costs	-	-	0.8	(6)	0.8
11	Municipal and other taxes	67.5	1.6	-		65.8
12	Cost of service	1,565.0	30.2	(16.1)		1,518.7
13	Utility income before income taxes					323.6
14	Income tax expense					15.7
15	Utility income					307.9

UGL UTILITY INCOME
2016 ACTUAL

Line No.	Particulars ($ millions)	Corporate (a)	Storage Unregulated Storage (b)	Adjustments (c)		Income Utility Income (d) =(a)-(b)+(c)
1	Gas sales and distribution	1,529.2	-	(14.7)	(1)	1,514.5
2	Transportation	182.2	(0.5)	-		182.7
3	Storage	95.6	87.1	-		8.5
4	Other operating revenue	20.8	-	(4.2)	(2)	16.5
5	Other income	1.0	(0.6)	(0.4)	(3)	1.2
6	Total operating revenue	1,828.8	86.0	(23.1)		1,723.4
7	Gas costs	716.8	1.7	(14.7)	(4)	700.4
8	Operation and maintenance	414.5	13.4	(3.2)	(5)	397.9
9	Depreciation and amortization expense	239.1	10.7	-		228.4
10	Fixed financing costs	-	-	1.0	(6)	1.0
11	Municipal and other taxes	71.2	1.6	-		69.6
12	Cost of service	1,441.6	27.4	(16.9)		1,397.3
13	Utility income before income taxes					326.2
14	Income tax expense					4.4
15	Utility income					321.8

UGL UTILITY INCOME
2017 ACTUAL

Line No.	Particulars ($ millions)	Corporate	Storage Unregulated Storage	Adjustments		Income Utility Income
		(a)	(b)	(c)		(d) =(a)-(b)+(c)
1	Gas sales and distribution	1,872.5	-	(15.6)	(1)	1,857.0
2	Transportation	236.5	(0.4)	-		236.9
3	Storage	126.9	119.1	-		7.8
4	Other operating revenue	24.3	-	(6.9)	(2)	17.3
5	Other income	(1.1)	(0.3)	(0.6)	(3)	(1.4)
6	Total operating revenue	2,259.1	118.4	(23.1)		2,117.6
7	Gas costs	1,070.5	23.9	(15.6)	(4)	1,031.0
8	Operation and maintenance	427.7	13.5	(0.8)	(5)	413.4
9	Depreciation and amortization expense	265.1	10.2	-		254.9
10	Fixed financing costs	-	-	1.0	(6)	1.0
11	Municipal and other taxes	73.7	1.4	-		72.3
12	Cost of service	1,837.0	49.0	(15.4)		1,772.6
13	Utility income before income taxes					344.9
14	Income tax expense					(5.0)
15	Utility income					350.0

UGL UTILITY INCOME
2018 ACTUAL

Line No.	Particulars ($ millions)	Corporate (a)	Storage Unregulated Storage (b)	Adjustments (c)		Income Utility Income (d) =(a)-(b)+(c)
1	Gas sales and distribution	1,812.6	-	(19.4)	(1)	1,793.1
2	Transportation	258.5	(0.4)	-		258.9
3	Storage	151.8	143.6	-		8.2
4	Other operating revenue	23.9	-	(6.1)	(2)	17.8
5	Other income	1.2	0.5	0.5	(3)	1.3
6	Total operating revenue	2,248.0	143.7	(25.1)		2,079.2
7	Gas costs	960.5	36.5	(16.8)	(4)	907.1
8	Operation and maintenance	461.9	13.5	(1.5)	(5)	446.9
9	Depreciation and amortization expense	287.5	10.7	-		276.9
10	Fixed financing costs	-	-	1.0	(6)	1.0
11	Municipal and other taxes	77.8	1.5	-		76.3
12	Cost of service	1,787.7	62.1	(17.3)		1,708.2
13	Utility income before income taxes					371.0
14	Income tax expense					(6.0)
15	Utility income					377.0

EGD UTILITY INCOME
2013 ACTUAL

Line No.	Particulars ($ millions)	Corporate (a)	Storage Unregulated Storage (b)	Adjustments (c)		Income Utility Income (d) =(a)-(b)+(c)
1	Gas sales and distribution	2,187.5	-	63.2	(1)	2,250.7
2	Transportation	317.0	-	(3.0)	(2)	314.0
3	Storage	1.6	-	-		1.6
4	Other operating revenue	49.0	-	(7.8)	(3)	41.2
5	Other income	94.2	-	(92.6)	(4)	1.6
6	Total operating revenue	2,649.3	-	(40.2)		2,609.1
7	Gas costs	1,449.5	-	73.3	(5)	1,522.8
8	Operation and maintenance	423.0	-	(12.1)	(6)	410.9
9	Depreciation and amortization expense	278.5	-	(0.5)	(7)	278.0
10	Fixed financing costs	2.4	-	-		2.4
11	Municipal and other taxes	40.2	-	(0.2)	(8)	40.0
12	Cost of service	2,193.6	-	60.5		2,254.1
13	Utility income before income taxes					355.0
14	Income tax expense					48.2
15	Utility income					306.8

EGD UTILITY INCOME
2014 ACTUAL

Line No.	Particulars ($ millions)	Corporate (a)	Storage Unregulated Storage (b)	Adjustments (c)		Income Utility Income (d) =(a)-(b)+(c)
1	Gas sales and distribution	2,762.3	-	(401.7)	(1)	2,360.6
2	Transportation	294.3	-	(14.3)	(2)	280.0
3	Storage	1.8	-	-		1.8
4	Other operating revenue	49.6	-	(6.0)	(3)	43.6
5	Other income	94.0	-	(93.7)	(4)	0.3
6	Total operating revenue	3,202.0	-	(515.7)		2,686.3
7	Gas costs	2,009.6	-	(364.7)	(5)	1,644.9
8	Operation and maintenance	431.9	-	(23.9)	(6)	408.0
9	Depreciation and amortization expense	279.2	-	(23.3)	(7)	255.9
10	Fixed financing costs	2.3	-	-		2.3
11	Municipal and other taxes	40.7	-	(0.2)	(8)	40.5
12	Cost of service	2,763.7	-	(412.1)		2,351.6
13	Utility income before income taxes					334.7
14	Income tax expense					6.1
15	Utility income					328.6

EGD UTILITY INCOME
2015 ACTUAL

Line No.	Particulars ($ millions)	Corporate (a)	Storage Unregulated Storage (b)	Adjustments (c)		Income Utility Income (d) =(a)-(b)+(c)
1	Gas sales and distribution	3,005.1	-	(562.3)	(1)	2,442.8
2	Transportation	329.3	-	(7.1)	(2)	322.2
3	Storage	1.9	-	-		1.9
4	Other operating revenue	50.2	-	(6.1)	(3)	44.1
5	Other income	111.1	-	(105.1)	(4)	6.0
6	Total operating revenue	3,497.6	-	(680.6)		2,817.0
7	Gas costs	2,284.1	-	(559.8)	(5)	1,724.3
8	Operation and maintenance	440.8	-	(10.1)	(6)	430.7
9	Depreciation and amortization expense	283.0	-	(23.3)	(7)	259.7
10	Fixed financing costs	3.4	-	-		3.4
11	Municipal and other taxes	41.8	-	(0.2)	(8)	41.6
12	Cost of service	3,053.1	-	(593.4)		2,459.7
13	Utility income before income taxes					357.3
14	Income tax expense					19.4
15	Utility income					337.9

EGD UTILITY INCOME
2016 ACTUAL

Line No.	Particulars ($ millions)	Corporate (a)	Storage Unregulated Storage (b)	Adjustments (c)		Income Utility Income (d) =(a)-(b)+(c)
1	Gas sales and distribution	2,407.3	-	(95.5)	(1)	2,311.8
2	Transportation	314.5	-	4.7	(2)	319.2
3	Storage	6.4	-	-		6.4
4	Other operating revenue	47.8	-	(5.9)	(3)	41.9
5	Other income	103.1	-	(102.0)	(4)	1.1
6	Total operating revenue	2,879.1	-	(198.7)		2,680.4
7	Gas costs	1,602.3	-	(105.2)	(5)	1,497.1
8	Operation and maintenance	460.5	-	(10.8)	(6)	449.7
9	Depreciation and amortization expense	316.1	-	(23.4)	(7)	292.7
10	Fixed financing costs	3.2	-	-		3.2
11	Municipal and other taxes	43.3	-	(0.2)	(8)	43.1
12	Cost of service	2,425.4	-	(139.6)		2,285.8
13	Utility income before income taxes					394.6
14	Income tax expense					17.3
15	Utility income					377.3

EGD UTILITY INCOME
2017 ACTUAL

Line No.	Particulars ($ millions)	Corporate (a)	Storage Unregulated Storage (b)	Adjustments (c)		Income Utility Income (d) =(a)-(b)+(c)
1	Gas sales and distribution	2,726.9	-	(223.5)	(1)	2,503.4
2	Transportation	401.2	-	(93.0)	(2)	308.2
3	Storage	19.0	-	-		19.0
4	Other operating revenue	47.2	-	(5.1)	(3)	42.1
5	Other income	83.0	-	(82.7)	(4)	0.3
6	Total operating revenue	3,277.3	-	(404.3)		2,873.0
7	Gas costs	1,991.1	-	(323.1)	(5)	1,668.0
8	Operation and maintenance	466.1	-	(34.6)	(6)	431.5
9	Depreciation and amortization expense	324.6	-	(23.3)	(7)	301.3
10	Fixed financing costs	2.8	-	-		2.8
11	Municipal and other taxes	44.8	-	(0.2)	(8)	44.6
12	Cost of service	2,829.4	-	(381.2)		2,448.2
13	Utility income before income taxes					424.8
14	Income tax expense					1.0
15	Utility income					423.8

EGD UTILITY INCOME
2018 ACTUAL

Line No.	Particulars ($ millions)	Corporate (a)	Storage Unregulated Storage (b)	Adjustments (c)		Income Utility Income (d) =(a)-(b)+(c)
1	Gas sales and distribution	2,748.0	-	(252.2)	(1)	2,495.8
2	Transportation	339.9	-	(63.6)	(2)	276.3
3	Storage	19.2	-	-		19.2
4	Other operating revenue	47.3	-	(5.0)	(3)	42.3
5	Other income	84.2	-	(84.0)	(4)	0.2
6	Total operating revenue	3,238.6	-	(404.8)		2,833.8
7	Gas costs	1,880.5	-	(314.5)	(5)	1,566.0
8	Operation and maintenance	437.0	-	(0.9)	(6)	436.1
9	Depreciation and amortization expense	318.0	-	(23.3)	(7)	294.7
10	Fixed financing costs	2.2	-	-		2.2
11	Municipal and other taxes	45.1	-	(0.2)	(8)	44.9
12	Cost of service	2,682.8	-	(338.9)		2,343.9
13	Utility income before income taxes					489.9
14	Income tax expense					38.5
15	Utility income					451.4

EGI UTILITY INCOME
PRELIMINARY 2022 RESULTS

Line No.	Particulars ($ millions)	Corporate (a)	Storage Unregulated Storage (b)	Adjustments (c)		Income Utility Income (d) =(a)-(b)+(c)
1	Gas sales and distribution	6,198.6	-	(34.0)	(1)	6,164.5
2	Transportation	146.2	(0.3)	(0.9)	(2)	145.7
3	Storage	179.4	172.4	(0.1)	(3)	6.9
4	Other operating revenue	71.8	2.3	(15.9)	(4)	53.6
5	Other income	13.0	(0.1)	(15.1)	(5)	(2.1)
6	Total operating revenue	6,609.0	174.3	(66.0)		6,368.6
7	Gas costs	3,678.6	31.7	(16.6)	(1)	3,630.3
8	Operation and maintenance	1,028.0	21.6	(3.9)	(6)	1,002.6
9	Depreciation and amortization expense	690.1	14.5	(22.5)	(7)	653.1
10	Fixed financing costs	3.5	0.0	1.1	(8)	4.6
11	Municipal and other taxes	120.4	1.9	0.0		118.5
12	Cost of service	5,520.6	69.7	(41.9)		5,409.0
13	Utility income before income taxes					959.6
14	Income tax expense					38.0
15	Utility income					921.6

Notes on Adjustments:

(1)	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(16.6)
	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(17.4)
		(34.0)
(2)	Elimination of the Union rate zone shareholder portion of net optimization activity (before tax)	(0.9)
(3)	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax)	(0.1)
(4)	Adjust EGD rate zone OBA costs to reflect EB-2013-0099 approved unit costs agreed to be used for determining net re	(4.8)
	Elimination of EGD rate zone Open Bill shareholder incentive	0.3
	Elimination of EGD rate zone shareholder portion of transactional service revenues	(4.8)
	Elimination of demand-side management incentive	(5.8)
	Elimination of EGD rate zone net revenue from ABC T-service, considered to be non-utility	(0.7)
		(15.9)
(5)	Elimination of Part VI.1 Tax from other income	(11.5)
	Elimination of interest income from investments not included in utility rate base	(0.1)
	Elimination of interest income from affiliates	(3.4)
		(15.1)
(6)	Elimination of donations	(1.1)
	Elimination of OEB penalty assessed in EB-2021-0204 (Assurance of Voluntary Compliance and Administrative Penalty	(0.3)
	Elimination of CFCAM charges	(8.4)
	Adjust unregulated storage back to legacy methodology instead of harmonized	6.0
		(3.9)
(7)	Eliminate amortization of PPD (purchase price discrepancy)	(22.5)
(8)	Interest on security deposits held during the year and included in elimination of corporate interest exp. Expense incurred to reduce bad debt. The average amount of the security deposit held during the year is applied as a reduction to the allowance for working capital in rate base	1.1

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-8-2, p.5

Question(s):

Enbridge has provided a table that shows accounting standard updates that “had no impact or an immaterial impact”. For the purpose of this table, what does Enbridge consider a “immaterial impact”.

Response:

Enbridge Gas considered any accounting standard update that impacted revenue requirement by less than $1 million to be immaterial.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory
Reference:

Exhibit 1, Tab 9, Schedule 1, p. 20

Question(s):

Over the deferred rebasing term (2019 to 2023), Enbridge Gas expects to incur approximately $252.2 million in capital expenditures related to integration efforts. Enbridge Gas has noted that the revenue requirement to support these investments was not included in base rates, and as such was borne by the shareholder.

a) Please confirm that investments (revenue requirement borne by the shareholder) on all capital expenditures (with the exception of recoveries related to approved Incremental Capital Module funding) and not just capital expenditures related to integration efforts are not included in base rates during the deferred rebasing term.

b) Please confirm that Enbridge Gas has requested that the net book value of integration-related capital spending incurred during the deferred rebasing term be added to the 2024 rate base.

Response:

a) Enbridge Gas agrees that during the deferred rebasing term none of its capital investments/additions (inclusive of integration investments), with the exception of approved projects which received ICM funding, were explicitly reflected in base rates. However, during the deferred rebasing term, the ICM threshold was used to determine the level of capital investments that were presumed to be recovered in base rates, before incremental funding through the ICM mechanism could be requested. Over the deferred rebasing term, capital projects related to integration were not included in the determination of annual ICM eligible amounts, as Enbridge Gas was expected to fund the revenue requirement for such projects through amalgamation synergies and savings. Specifically, integration related capital investments were excluded from the annual total in-service capital forecasts, which were then compared to the annual ICM threshold values to determine the maximum ICM eligible capital amount as part of the Company’s annual rate proceedings. As such, integration related capital projects were expressly assumed not to be recovered through base rates.

b) Confirmed. Enbridge Gas has proposed that the net book value of the integration-related capital be added to 2024 rate base to match the regulatory treatment of the annual synergies generated, which are included in the revenue requirement and are being used to fund the capital invested.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T9/S1/pp. 3-4

Question(s):

"Enbridge Gas undertook significant investments during the rebasing term, in both OM&A and Capital, to deliver the anticipated savings. Enbridge Gas defined integration costs as one-time incremental costs required to deliver value for an opportunity or set of opportunities related to utility integration, and included items such as labour, consulting and capital expenditures. Integration costs, both OM&A and capital expenditures, were identifies and managed separately throughout the deferred rebasing term. These investments were made to deliver the highest level of sustainable savings to customers, even as investments in the latter years of the term provide limited opportunity for Enbridge Gas to benefit from these investments as the sustained savings would be rebased at the end of the rebasing term. At the time these savings are rebased to customers, so are the corresponding net book value of integration capital costs."

"Integration results were delivered through a portfolio of initiatives governed by senior leadership and enabled through a program office."

a) Please set out a list of all of the one-time incremental integration costs incurred during the 5-year rebasing period, both OM&A and capital;

b) Please list the portfolio of specific initiatives that were enabled through the program office;

c) Please specifically identify the quantitative and qualitative benefits and costs for each specific initiative;

d) Please provide a complete list of all cost savings embedded in the 2024 Revenue Requirement related to the merger;

e) Please describe the process undertaken internally to define merger costs and savings;

f) Please indicate whether EGI retained external consultants to assess these costs and savings. If so, please provide any reports prepared by these consultants.

Response:

a) Please see Exhibit 1, Tab 9, Schedule 1, pages 17 to 19 for a listing and explanation of O&M expenditures and Exhibit 1, Tab 9, Schedule 1, Attachment 1 for a listing and explanation of Capital Expenditures.

b) The Program Office enabled priority initiatives that crossed multiple areas. Attachment 1 lists these initiatives, their descriptions, and their supporting qualitative benefits. These initiatives aligned policies, programs, processes, and procedures for customers and for internal teams, created alignment for delivering services to stakeholders through common operating models, and generated an aligned asset management program. While many initiatives also delivered quantitative savings (please see response at part c), the qualitative benefits for the integration portfolio were delivered to support safe, reliable and effective operations, while effectively managing risk.

c) The integration portfolio delivered the qualitative benefits as listed in Attachment 1. The quantitative savings for each initiative were reviewed individually, and the following methodologies were used to calculate the savings: For organizational restructuring, roles were identified for elimination and removed, and all FTE costs were removed from the corresponding budget; for non-labour initiatives, Enbridge Gas departments quantified the savings, and the sustainable amounts were removed from the corresponding budgets. Further information on the initiatives by type with supporting quantitative benefits and costs are in Table 1:

Table 1
Integration Initiative Quantitative Benefits

Initiative Type	Department	Sustained Savings in 2024 Rates	Total Benefit Over Term	Total CapEx Over Term
			$millions	
Integration Portfolio Roles				2
Alignment of Policies, Programs, Processes and Procedures	Business Development and Regulatory	1.7	7	
	Energy Services		-	23
	Engineering	1.7	6	0
	Operations	2.3	9	65
Cost Rationalization	Business Development and Regulatory	2.1	11	
	Engineering		0	
	Engineering & STO	0.3	1	
	Operations	1.4	6	
	Shared Services: REWS	1.0	4	67
Customer Care Integration	Business Development and Regulatory	0.1	1	3
	Customer Care	16.6	40	72
	Energy Services		-	
	Operations		-	16
Integration & Execution of Operating Models	Operations	3.7	12	3
Organizational Restructuring (Labour)		54.9	231	
Total		86.0	328	252

d) Integration savings (in millions) in the 2024 Test Year Forecast is as follows:

Table 2

Line No.	Type	2019	2020	2021	2022	2023	2024	
		(a)	(b)	(c)	(d)	(e)	(f)	
1	Alignment of Policies, Programs, Processes & Procedures	1.7	3.4	5.5	5.6	5.7	5.7	
2	Cost Rationalization	2.6	4.2	4.9	4.9	4.9	4.9	
3	Customer Care Integration	2.8	2.9	1.8	16.8	16.8	16.8	
4	Integration & Execution of Operating Models		0.1	4.3	3.7	3.7	3.7	
5	Organizational Restructuring (Labour)	25.1	41.8	54.8	54.8	54.9	54.9	
6								86.0

e) Costs were deemed integration related if they were one-time incremental costs required to deliver value and were deemed necessary to bring together Union Gas and EGD to a single efficient structure. Savings were deemed integration related if the benefits were sustainable and resulted from the integration of the two legacy utilities during the 5-year deferred rebasing term. Both costs and savings would not have occurred without the merger.

f) No. Enbridge Gas did not retain external consultants to assess these costs and savings.

Initiatives Enabled by Program Office

Department	Initiative	Description / Qualitative Benefits
Business Development and Regulatory	2024 Rebasing	This project developed EGI plans for filing the 2024 Rebasing application.
	Align the Enbridge Brand	This project successfully completed the rebranding of various asset groups, including signage, vehicles, apparel, external applications, customer communications, social media, and EGI websites.
	In-franchise Service Harmonization	This project conducted a high-level review of existing legacy in-franchise and ex-franchise services to develop proposals for harmonized services in support of the Rebasing application.
	Integrated Resource Planning	This project develops harmonized processes and procedures and integrates with the AMP processes to ensure growth reinforcement infrastructure applications review and consider alternative options to new infrastructure build submissions, further supporting DSM, Energy Transition and stakeholder expectations.
	Rates and Service Harmonization Proposal	This project developed detailed proposals for the harmonized services and rates to support the 2024 rebasing application, including rate class and rate zone proposals. EGI consulted with customers and customer associations to help with the shaping of the harmonized proposals.
	Web Integration	This project consolidated information into the new harmonized enbridgegas.com website from two primary websites and six microsites to better reflect the needs of the integrated utility. The navigation architecture provides a harmonized web service presence for all our business units, supports our revenue-generating product and service offerings, and supports the move to increased self-serve options. Along with meeting the requirements contained in The Accessibility for Ontarians with Disabilities Act (AODA), the new website is also fully brand compliant, for a more positive customer experience.
Corporate	Connect	This project was an enterprise driven initiative that provided our field technicians and supporting staff with an enterprise grade, consolidated solution for executing EGI work in the field.
	Enterprise Asset Management Alignment	This project implemented a harmonized, enterprise-wide framework to optimize realized value from our assets through defendable and repeatable decisions that balance costs, opportunities and risks against the desired performance over the lifecycle of our assets.
	Learning Fusion/Workday Learning	This project designed and implemented one learning and development strategy, consolidated and upgraded training course content and a single Learning Management System across the EGI and the enterprise.
Customer Care	Contract Market Harmonization	This project will integrate the key systems and processes for contract markets, including Large Volume (LV), Direct Purchase (DP), Storage and Transmission (S&T), and Gas Supply, and facilitate in-franchise and ex-franchise service harmonization to deliver an outstanding customer experience.
	Customer Information System (CIS) Integration	This project integrated EGI to a common Customer Information System (CIS) resulting in the retirement of the Union Gas Banner CIS, which also required an upgrade and migration to one SAP platform to ensure ongoing reliable operations.
	Large Volume Customer Operating Rule and Process Harmonization	This project developed and implemented harmonized rules that govern how contract parameters are established in the contract rate market, how compliance/authorization of overrun is managed, and developed consistent customer communication templates. These changes have created a more consistent customer experience across all rate zones, support growth of the system, reduced the level of effort to manage contract renewals, and increased the level of transparency for our customers.
Energy Services	Cost of Gas Automation	This project integrated EGD processes into the existing automated utility gas purchase and financial reporting system in SAP for Energy Services and Finance, delivering a consolidated system and processes across EGI. The integrated system provides functionality for gas inventory and financial revenue reporting related to cost of gas processes, including contracting, purchasing, invoicing, and nominations.
	Ex-franchise Service & Rate Harmonization	This project reviewed and recommended the underpinning service and rate design proposal for the ex-franchise contracted services of the integrated utility to support the Rebasing application.
	In-franchise Service Management	This project defined the accountabilities and processes for creating, facilitating, and maintaining new and existing services for In-franchise customers.
	Large Volume Measurement Systems Integration	This project is aligning the large volume measurement systems across GDS, leading to consistent volume measurement data validation for all contract large volume customers.
	Gas Control Centre Consolidation and SCADA Migration	This project consolidated the Edmonton and Chatham Gas Control Centres in Chatham, and migrated the EGD SCADA (Supervisory Control and Data Acquisition) system to the Cygnet SCADA system resulting in a single Gas Control Centre and SCADA solution for EGI that continues to deliver safe, reliable, and efficient operations.
	Utility Weather & Demand Harmonization	This project successfully developed harmonized Weather and Demand planning processes to provide customers a reliable service with the Gas Supply Plan, storage, transmission, and distribution systems, at a reasonable cost. This work is included in the harmonization proposal for rebasing, identifying harmonized Heating Degree Day and Design Day demand methodologies.
Engineering	Community Expansion Process Integration	This project integrated and standardized processes and procedures to support the community expansion program. These new processes and procedures cover all six stages of the project lifecycle and have been integrated with the new EGI organizational structure and systems that support our efforts to grow the business.
	Consolidated Asset Management Plans	This project developed the first consolidated Asset Management Plan (AMP) for EGI that was filed with the OEB on October 15, 2020. This AMP supported the 2021 budget and provided the basis for the long-range plan. Through this effort a consistent value-based decision-making framework was developed to standardize our approach to optimizing the investment portfolio based on cost, risk, and performance. The project required the establishment of a common AMP approach, processes, and procedures, including the corresponding tools that are used to support decision making (i.e., Copperleaf C55).
	Content Management Program	This project is managing the integration and implementation of policies, processes, procedures and design specifications, including technical content and Operating Standards across Operations and Engineering to mitigate EGI risks and to ensure code compliance.
	Cross Bore Risk Mitigation	This project investigated and assessed the current risk associated with trenchless installations using historical construction information and industry leading practices. Updated construction practices and procedures, including probability and risk management tools, were developed to address both historical installations, as well as to reduce the potential creation of any new cross bores. Common practices have been employed across EGI.
	EGI Copperleaf C55 Implementation	This project introduced a new asset management application Copperleaf (C55) that went live at EGI to hundreds of users in January 2020; and this tool and its associated processes are helping make investment decisions more consistently, transparently, and aligned with the organization's strategic goals. The successful implementation and launch also served to align EGI with the Enterprise Asset Management approach and systems.
	Integrity Management Program Evolution	This project is being completed in phases over multiple years and included the harmonization of the Integrity Management Program, practices and systems for EGI, followed by the alignment to the Enterprise Standard, as well as addressing assurance observations and making improvements by implementing industry leading practices.
	Management of Change Program Implementation	This project delivered a new integrated Management of Change (MOC) standard and process, with a focus on departmental triggers for making changes and how to manage them safely. MOC is a critical element of the Integrated Management System, and this was a pivotal effort to enhance operational safety and reliability.
	Records Management Strategy	This project conducted current and future state analysis developing an end-to-end view of how records are created and used, and how to address challenges and opportunities for improvement of records management across the gas carry asset lifecycle. The outcome of this strategy work was a vision, including scope, a high-level roadmap to support the future design and implementation of integrated records management processes, resources, and systems for Operations and Engineering.
	Integrated Management Systems	This project harmonized the Integrated Management System (IMS) governance and framework. In addition, it identified and implemented process efficiencies, integrated the elements of the IMS, and governed the integration of the eight IMS management programs to meet applicable IMS and management program requirements to support safe and reliable operations. Management Programs included: Asset, Emergency, Environmental, Health & Safety, Integrity, Security, Damage Prevention and Control Room.

Operations	Operating Standards Integration and Implementation	This project supported through the Content Management Program, developed and implemented a number of priority Operating Standards for EGI, including but not limited to Easement and Pipeline Markers, Corrosion Survey, Leak Repair and Leak Survey, Measurement and Regulators Station Inspections, Pressure Regulation and Protection, and Valve Inspection and Repair.
	Customer Attachment Harmonization	This project is aligning our customer attachment policies, systems and processes to support our growth strategies and to enhance our customers experience. This project is being implemented in phases in conjunction with the EGI Sync program.
	Damage Reduction Strategy Program	This project represents the implementation of a collection of strategic harmonized multi-year initiatives aimed at reducing third-party damages to EGI assets. Initiatives are centered on awareness, education, and partnerships, and 3rd party Advertising/Marketing firms are helping to ensure effective communications and engagement with contractors and homeowners. Additionally, technology and predictive analytics will be employed to enable a more proactive approach to distribution protection measures and practices.
	Distribution Operations Workflow Integration	This project reviewed EGD and Union Distribution Operations workflow processes, identified differences, and made recommendations for harmonized processes, as well as identified gaps for resolution. These outcomes were used to define the integrated operations future state processes and system requirements to support other initiatives such as the Asset & Work Management System (Maximo) integration.
	EGI Sync Program	EGI Sync is a program that is driving EGI transformation and integration through ground up business unit readiness, alignment, prioritization, sequencing and implementation of the EGI Asset and Work Management System (AWS), Enterprise Mobility (Connect), and Customer Information Systems (CIS) solutions.
	Integrated Utility Asset & Work Management System (AWS Phase 1)	This project delivered the foundational integrated Utility Asset & Work Management System (Maximo) for Utilization and Maintenance work to support effective utility planning, decision making and work execution, focusing on policies, processes and procedures, and aligning where operationally feasible.
	Integrated Utility Asset & Work Management (AWS Phase 2 & 3)	This project is building upon the foundational Utility Asset & Work Management System (AWS) project to integrate additional work management related systems and processes within Maximo by aligning Construction, Customer Attachment and Meter Shop systems and processes for Maximo, Get Connected, and Customer Connections Work Suite systems. This work also included the integration with External Alliance Partner systems and processes for our business teams, impacting over 2,600 end users. AWS Phase 3 is enhancing work management efficiencies through the migration of Union Distribution Station Operations and Telemetry assets to Maximo, Click Schedule and Mobile, including the alignment of supporting systems, processes, procedures, and performance measures and reporting.
	Work and Resource Strategy Implementation	This project enabled the successful implementation of our Work and Resource Strategy to align the operating model for Distribution Operations to our environments of remote, rural, urban, and metro. It also ensured the identified insourced and outsourced work and resource plans were implemented across all regions and levels. This initiative also ensured both external service providers and internal resources are available, engaged, trained, and have the tools, processes, and procedures to complete work.
	Work Management Integration	This project is implementing the work management strategy delivering an optimized combination of organization, processes, and systems for Distribution Operation's front and back-end functions that support work planning, scheduling, execution, closure and analysis. This project delivers the consolidation of Work Management Centres.
	Emergency Response Structure and Procedures Manual	This project aligned the Emergency Operations Centre (EOC) and Incident Command protocols for the utility, and produced an integrated Emergency Procedures Manual for EGI which was filed with the Canadian Energy Regulator prior to the regulatory deadline of April 1, 2020. This effort defined consistent emergency response procedures, training, an integrated on-call schedule for all EGI Incident Command System groups, and developed a consistent notification and EOC trigger criteria and process.
	Fleet Maintenance & Garage Strategy	This project successfully aligned all EGI Fleet assets with the enterprise fleet management preventative maintenance platform (Element), consolidated and optimized fleet maintenance operations, and created an amalgamated central fleet management support team, providing clear and consistent accountability, standards, processes, and support.
	Warehouse and Material Management and Logistics	This project consolidated the material warehouses from four facilities (located at Niagara, Markham, London and Sudbury) to two (located in Markham and London), streamlining material management and logistics across EGI.
Shared Services: Safety & Reliability	Safety Program Integration	This project is harmonizing all the safety programs for EGI to ensure a consistent standard of safety is available for all employees at EGI.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T9/S1/p. 5/ Tables 2 and 3

Question(s):

Tables 2 and 3 set out Integration Savings as Achieved by Category and Integration Savings as Achieved by Area.

a) For each of the 2023 amounts in these two Tables please provide a detailed explanation as to how they were calculated. Please include all assumptions;

b) Please recast the Tables 2 and 3 to include the amounts of savings embedded in the 2024 Revenue Requirement. Please provide a detailed explanation as to how these amounts were calculated.

c) Please provide a forecast of any further integration savings for the years 2025-2028

Response:

a) Please see response at Exhibit I.1.9-CCC-25 part c) for explanation of how savings were calculated.

b) The savings that are listed under the 2023 Bridge Year are the full integration synergy savings forecast to be achieved through to the end of 2023 and represents the amount that has been embedded in the 2024 Test Year Forecast.

c) Integration savings of $86 million are sustainable and included in the 2024 Test Year Forecast and beyond. Please see response at Exhibit I.1.9-CCC-25 part d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T9/S1/p. 25

Question(s):

The evidence states, "The annual integration synergies of $86 million demonstrate the amalgamation Of EGD and Union provides ongoing benefits to customers. As those savings are passed on to customers in 2024, it is appropriate the corresponding net book value of integration costs of the assets used to provide continued safe and reliable services are included in rate base." Is EGI seeking to add the net book value to 2024 ratebase of all of its integration projects? If not, please identify those that are not in Attachment 1.

Response:

a) Please see response at Exhibit I.1.9-STAFF-22 part b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 1, Tab 9, Schedule 1, p. 11 of 25

Question(s):

At page 11, EGI indicates that it has driven savings by aligning the use of contractors for specific work activities.

a) Please clarify what EGI means by aligning contractors for specific work activities. For instance, does EGI mean that internal resources no longer complete those work activities, or simply that the processes EGI uses to determine when contractors should be used for those tasks is now common across the company.

Response:

a) This initiative aligned the work that would be performed by contractors versus internal staff at Enbridge Gas. This resulted in a reduction of FTEs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 1, Tab 9, Schedule 1, pp. 20, 24 of 25

Question(s):

At page 11, EGI indicates that it spent $252.2 million in capital expenditures related to integration efforts, which currently have an undepreciated balance of $178.5 million, and a 2024 revenue requirement impact of $34 million. At page 24, EGI states that the annual synergy savings as a result of integration are $86 million per year.

a) Does EGI track the synergy savings driven specifically by the investments made during the deferred rebasing period, versus how much of the synergy savings could have been achieved through integration without the capital expenditures?

b) If the answer to (a) is yes, please provide the amount of integration savings that were attributable to integration without the capital expenditures.

c) Does EGI track the relative impact of any specific capital expenditure related to integration? For instance, the customer information system had a capital expenditure cost of $X and drove $Y in sustainable synergies for ratepayers?

d) If the answer to (c) is yes, please provide the cost and benefits (in sustained synergy savings) of each project.

Response:

a) Enbridge Gas tracks synergy savings for the portfolio of initiatives as outlined in response at Exhibit I.1.2-CCC-25. Enbridge Gas does not track the integration synergy savings that could have been achieved without capital expenditures.

b) Please see part a).

c) Please see response at Exhibit I.1.2-CCC-25 for how initiatives were tracked in the portfolio.

d) Please see part c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit 1, Tab 9, Schedule 1, Table 3, line 6 - *Central Functions*

Question(s):

a) Please confirm that compared to legacy costs, in 2022 EGI is saving $15.8 million as a result of centralized functions. Is this for both Union and EGI?

b) Please provide the legacy costs from 2015-2020 for services now centralized for Union and EGI, including each of utility in house services and centralized functions provided by EI.

c) Please provide explanatory notes and references to filings in prior cases.

d) Please provide the details of the services and costs of EI centralized services for 2015-2022. Reconcile to Intercorporate Services Agreement for 2022.

Response:

a) Confirmed, in 2022 Enbridge Gas saved $15.8 million as a result of synergy initiatives that were related to both EGD and Union.

b) Enbridge Gas believes that the reference to ‘Union and EGI’ above should read ‘Union, EGD and Enbridge Gas’ and the reference to ‘centralized functions provided by EI’ represents ‘Enbridge Inc. or Spectra Allocations’. Enbridge Gas has also extended the data range to 2015 to 2024 to address other requests. Please see Attachment 1 for the 2015 to 2024 costs.

c) Explanatory notes have been included in the response for part b). References to filings are listed in Table 1.

Table 1
Filing References

Year	EGD	Union	EGI
2015*	EB-2016-0142, Exhibit B, Tab 4, Schedule 2, Page 1	EB-2016-0118, Exhibit A, Tab 2, Appendix A, Schedule 13	
2016*	EB-2017-0102, Exhibit B, Tab 4, Schedule 2, Page 1	EB-2017-0091, Exhibit A, Tab 2, Appendix A, Schedule 13	
2017*	EB-2018-0131, Exhibit B, Tab 4, Schedule 2, Page 1	EB-2018-0105, Exhibit A, Tab 2, Appendix A, Schedule 13	
2018**	EB-2019-0105, Exhibit B, Tab 2, Appendix D, Schedule 2, Page 1	EB-2019-0105, Exhibit C, Tab 2, Appendix A, Schedule 13	
2019			EB-2022-0110, Exhibit I.FRPO.5 Attachment 1 Pages 1-2
2020			EB-2022-0110, Exhibit B, Tab 3, Schedule 1, Page 5
2021			EB-2022-0110, Exhibit B, Tab 3, Schedule 1, Page 5

Notes:

*2015-2017 amounts as filed and referenced use the historical EGD and Union Gas allocation methodologies.

**2018 amounts as filed and as referenced used the historical EGD and Union Gas allocation methodologies for consistency. However, the new central functions allocation methodology was in place for this and subsequent years.

d) Please see Attachment 1 for the details of services and costs of EI centralized services for 2015 to 2022 Estimate. The 2022 Estimate reconciliation to the 2022 ISA can be found in response at Exhibit I.4.4-EP-70.

EI or Spectra Allocated

Line No	Description	2015 (a) Actuals	2016 (b) Actuals	2017 (c) Actuals	2018 (d) Actuals	2019 (e) Actuals	2020 (f) Actuals	2021 (g) Actuals	2022 (h) Estimate	2023 (i) Bridge	2024 (j) Test
1	Aviation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Corporate Development Office (CDO)	0.9	1.3	1.0	1.5	1.5	1.5	1.6	2.4	2.4	2.5
3	Enterprise Asset & Work Mgmt (EAWM)	0.0	0.0	0.0	0.0	0.0	0.2	0.6	1.8	1.8	1.9
4	Executive	1.9	1.9	3.6	0.6	0.6	0.6	0.6	1.1	1.1	1.1
5	Finance	1.8	2.0	1.5	30.1	25.2	25.0	28.4	35.1	35.9	36.7
6	Real Estate & Workplace Services (REWS)	0.5	0.4	0.0	2.1	26.1	30.4	26.7	27.4	28.1	28.7
7	Human Resources (HR)	14.9	13.8	16.4	20.5	22.9	25.5	22.1	24.7	25.3	25.9
8	Legal	2.0	0.8	1.1	10.4	13.7	11.0	11.0	14.7	15.0	15.3
9	Public Affairs and Communications (PAC)	0.1	0.7	0.6	5.0	5.3	5.6	4.3	6.3	6.5	6.6
10	Safety & Reliability (S&R)	0.8	0.8	1.1	1.0	5.7	8.1	6.8	7.2	7.4	7.5
11	Supply Chain Management (SCM)	2.4	3.0	3.0	7.5	7.4	11.2	8.2	11.7	12.0	12.2
12	Technology Information Systems (TIS)	16.0	19.6	18.1	59.4	70.2	66.0	75.0	108.3	125.4	139.7
13	Benefits	0.0	0.0	0.0	34.1	27.2	26.6	57.1	60.3	64.8	66.1
14	Depreciation	6.8	6.2	6.8	20.4	20.9	21.2	22.0	20.0	20.0	25.6
15	Insurance	5.1	5.1	4.4	9.9	10.6	11.7	15.4	15.7	7.2	7.3
16	**Aggregated CF Costs**	**53.2**	**55.6**	**57.6**	**202.5**	**237.3**	**244.6**	**279.8**	**336.7**	**352.9**	**377.1**

In House Costs

Line No	Description	2015 (k) Actuals	2016 (l) Actuals	2017 (m) Actuals	2018 (n) Actuals	2019 (o) Actuals	2020 (p) Actuals	2021 (q) Actuals	2022 (r) Estimate	2023 (s) Bridge	2024 (t) Test
1	Aviation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Corporate Development Office (CDO)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Enterprise Asset & Work Mgmt (EAWM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Executive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Finance	21.3	29.6	32.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Real Estate & Workplace Services (REWS)	28.8	29.7	28.8	24.2	0.0	0.0	0.0	0.0	0.0	0.0
7	Human Resources (HR)	20.3	19.9	22.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Legal	4.6	4.5	5.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Public Affairs and Communications (PAC)	1.6	1.7	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Safety & Reliability (S&R)	5.6	4.9	5.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0
11	Supply Chain Management (SCM)	3.8	2.9	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Technology Information Systems (TIS)	52.2	54.0	50.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Benefits	43.3	41.9	37.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Insurance	5.2	4.2	3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Aggregated CF Costs**	**186.7**	**193.3**	**190.4**	**28.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Total CF Costs

Line No	Description	2015 (u) Actuals	2016 (v) Actuals	2017 (w) Actuals	2018 (x) Actuals	2019 (y) Actuals	2020 (z) Actuals	2021 (aa) Actuals	2022 (ab) Estimate	2023 (ac) Bridge	2024 (ad) Test
1	Aviation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Corporate Development Office (CDO)	0.9	1.3	1.0	1.5	1.5	1.5	1.6	2.4	2.4	2.5
3	Enterprise Asset & Work Mgmt (EAWM)	0.0	0.0	0.0	0.0	0.0	0.2	0.6	1.8	1.8	1.9
4	Executive	1.9	1.9	3.6	0.6	0.6	0.6	0.6	1.1	1.1	1.1
5	Finance	23.1	31.6	33.7	30.1	25.2	25.0	28.4	35.1	35.9	36.7
6	Real Estate & Workplace Services (REWS)	29.3	30.1	28.8	26.3	26.1	30.4	26.7	27.4	28.1	28.7
7	Human Resources (HR)	35.2	33.7	38.7	20.5	22.9	25.5	22.1	24.7	25.3	25.9
8	Legal	6.6	5.3	6.8	10.4	13.7	11.0	11.0	14.7	15.0	15.3
9	Public Affairs and Communications (PAC)	1.7	2.4	1.8	5.0	5.3	5.6	4.3	6.3	6.5	6.6
10	Safety & Reliability (S&R)	6.4	5.7	6.1	4.8	5.7	8.1	6.8	7.2	7.4	7.5
11	Supply Chain Management (SCM)	6.2	5.9	5.9	7.5	7.4	11.2	8.2	11.7	12.0	12.2
12	Technology Information Systems (TIS)	68.2	73.6	69.0	59.4	70.2	66.0	75.0	108.3	125.4	139.7
13	Benefits	43.3	41.9	37.5	34.1	27.2	26.6	57.1	60.3	64.8	66.1
14	Depreciation	6.8	6.2	6.8	20.4	20.9	21.2	22.0	20.0	20.0	25.6
15	Insurance	10.3	9.3	8.3	9.9	10.6	11.7	15.4	15.7	7.2	7.3
16	**Aggregated CF Costs**	**239.9**	**248.9**	**248.0**	**230.5**	**237.3**	**244.6**	**279.8**	**336.7**	**352.9**	**377.1**

Notes:

Costs for 2015, 2016 and 2017 do not represent the CFCAM model costs found in Exhibit 4, Tab 4, Schedule 3, Table 3. Allocations models for Union Gas and EGD along with Central Functions resources in each company were different for those years. These costs should be utilized for illustrative purposes only.

In house costs for 2018 were included in the CFCAM model costs found in Exhibit 4, Tab 4, Schedule 3, Table 3 and Exhibit 4, Tab 4, Schedule 2, Table1, Line 5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit 1, Tab 9, Schedule 1, Page 21, Table 6

Question(s):

a) Please explain how Actual Overheads of $7.6 million for 2019 and $11.0 million for 2020 were determined.

b) Why are there no overheads shown after 2020?

Response:

a) The calculation of overheads for 2019 and 2020 is based on the historical EGD and Union overhead capitalization policies. These are provided at Exhibit 2, Tab 4, Schedule 2, pages 3 to 7. The actual overhead allocation rates to apply to projects were determined by rate zone and applied to all projects as the proportion of overheads relative to the total direct capital spend.

b) Enbridge Gas started allocating overheads at the project level starting in 2021. This is provided at Note 4 in Exhibit 1, Tab 9, Schedule 1, Table 6. Consequently, overheads are contained in the values for lines 1 to 6 from 2021 onwards.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit 1, Tab 9, Page 24, Paragraph 50

Question(s):

Please file a table that shows the components of the $86 expected annual synergy savings by year over the 2024 to 2028 period.

Response:

Integration savings of $86 million are sustainable and included in the 2024 Test Year Forecast and beyond. Please see response at Exhibit I.1.9-CCC-25 part d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-9-1

Question(s):

With respect to integration savings:

a) [p.5] For each category listed in Table 2, please provide a breakdown of each specific initiative, detail the methodology used to calculate the savings, and provide the underlying calculations.

b) [p.5, 17] Please expand Tables 2, 3, 5 and 6 to include forecasts for 2024 to 2028.

c) Please provide the most recent internal reporting to Enbridge's senior management and Enbridge Inc. regarding integration savings.

Response:

a) Please see response at Exhibit I.1.9-CCC-25 parts a-c) for a listing of the integration initiatives, the associated qualitative and quantitative benefits, and the methodology to calculate these savings.

b) O&M integration savings of $86 million are sustainable and included in the 2024 Test Year Forecast. As provided at Exhibit 1, Tab 9, Schedule 1, page 16, there will be no incremental integration savings or costs beyond 2023 and therefore no incremental integration savings or costs forecasted for 2024 to 2028. For capital integration costs, the Company's proposal is that the net book value of these costs will be included in rate base in 2024 and be subject to recovery through rates going forward as these costs are funded through the integration synergies that have been achieved through the amalgamation of EGD and Union.

c) Please see response at Exhibit I.1.2-SEC-76, Attachment 2, page 8 for Enbridge Inc. Reporting on integration savings.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-9-1, p.21; 9-2-1, p.22

Question(s):

With respect to integration capital:

a) Please provide the 2024 revenue requirement, broken down into each major component (rate base, return on capital, depreciation, taxes), for all integration capital that Enbridge seeks to add to the rate base.

b) Please also provide the Tax Variance Deferral Account (TVDA) balance related to integration capital.

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023. /u

a) Please see below for the 2024 forecast revenue requirement applicable to integration capital:

($ millions)	2024 Revenue Requirement	
Rate Base	112	/u
Depreciation (1)	15	/u
Interest Expense	3	/u
Return on Capital	5	/u
Income Tax	5	/u
Total (2)	28	/u

Notes:
(1) Depreciation per the revised depreciation rates proposed in Exhibit 2, Tab 5, Schedule 4, Attachment 1. /u
(2) Revenue requirement would be $47 million with existing depreciation rates reflected. /u

b) The forecast TVDA balance related to integration capital is approximately $6.8 million payable. The change in this balance from the original 2023 estimated ending balance is impacted by the mix of 2022 integration in-service actuals that differed from the 2022 original estimate, including the shift of the AWS project to 2023. This impact is partially offset by reductions to 2023 integration capital as part of the capital updates, including the deferral of the GTA REWS projects. /u

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-9-1

Question(s):

In addition to saving arising from integration activities, please detail all other productivity and efficiency measures that the applicant has taken since 2018 and plans to take through to the end of the test year. Please quantify those actual and forecast savings and explain the calculations.

Response:

Please see Table 1 for the productivity savings Enbridge Gas has achieved since 2018 and plans to take through to the end of the test year:

Table 1
EGI Productivity Savings

Line No.	Particulars ($millions)	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)	(d)	(e)	(f)
	Business Development & Regulatory						
1	Process Optimization*	-	-	0.4	0.2	0.2	0.2
2	Cost Rationalization**	0.3	0.3	0.3	0.3	0.3	0.3
3	Embedded productivity***	-	-	-	-	0.5	0.5
	Customer Care						
4	Process Optimization*	5.3	15.8	14.1	13.9	13.9	13.9
5	Embedded productivity***	-	-	-	-	1.0	1.1
	Energy Services						
6	Process Optimization*	-	-	0.2	0.1	0.1	0.1
	Engineering & STO						
7	Process Optimization*	0.1	0.1	0.7	0.4	0.4	0.4
8	Cost Rationalization**	2.5	2.4	2.4	2.4	1.9	1.9
9	Embedded productivity***	-	-	-	-	8.0	9.5
	Operations						
10	Process Optimization*	-	-	0.6	0.3	0.3	0.3
11	Embedded productivity***	-	-	-	-	4.4	7.0
12	Total Productivity Savings	8.2	18.6	18.6	17.6	31.0	35.2

*Process Optimization initiatives relate to changes in the way work is organized to achieve efficiencies. Please see Exhibit 4, Tab 4, Schedule 2, paragraph 16 for details of significant initiatives.
** Cost Rationalization relates to spend that could be eliminated.
*** Please see Exhibit 4, Tab 4, Schedule 2, paragraph 17 for further information on embedded productivity.

Similar to integration savings provided in response at Exhibit I.1.9-CCC-25, to calculate the productivity savings, each budget cycle, Enbridge Gas conducts a detailed review of savings that were achieved by the business. When sustainable savings are achieved, those amounts are removed from the budget as the costs are no longer applicable and tracked separately.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit 1, Tab 9, Schedule 1, Tables 1, 2,3

Question(s):

a) Please clarify whether the "Potential" savings shown in Table 1 are net of integration costs and are calculated as the net total over 10 or 5 years?

b) Please clarify whether the savings shown in Tables 2 & 3 are net of the integration costs as shown in Table 5.

Response:

a) The "Potential" savings in Table 1 are not net of integration costs. The ranges in Table 1 were provided as filed in the MAADs Application[1], and contemplated a 10-year deferred rebasing term.

b) The savings shown in Tables 2 and 3 are not net of integration O&M costs. Enbridge Gas is not requesting recovery of the O&M costs.

[1] EB-2017-0306.

ENBRIDGE GAS INC.

Answer to Interrogatory from Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit 1, Tab 9, Schedule 1, Table 5

Question(s):

a) Please update Table 5 to include 2022 actual results.

Response:

a) Please see the updated Table 5:

Table 5
Integration O&M Costs Schedule by Area

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	Total
			(a)	(b)	(c)	(d)	(e)	(f)
1	Distribution Operations	EGI	2.6	18.0	21.9	22.1	10.9	75.5
2	Engineering & STO	EGI	1.6	8.3	6.9	6.2	6.2	29.3
3	Customer Care	EGI	2.0	14.0	13.8	0.1	0.5	30.4
4	Energy Services	EGI	0.7	1.0	0.5	0.5	0.6	3.2
5	BD&R	EGI	0.0	0.3	0.9	0.4	0.5	2.1
6	Central Functions	EGI	3.2	4.8	5.8	1.3	0.9	16.0
7	Subtotal for Integration Costs	EGI	10.2	46.4	49.8	30.6	19.5	156.5
8	Integration Severance	EGI	41.5	77.7				119.1
9	Total Integration-Related Costs	EGI	51.7	124.1	49.8	30.6	19.5	275.6

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit 1, Tab 9, Schedule 1, Table 6

Question(s):

a) Please update Table 6 to include 2022 actual results.

b) Please provide a table similar to Table 6 which shows integration related in-service additions by year along with the additions to depreciation related to those additions (i.e., as per continuity schedules).

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023. /u

a) Please see the revised Table 6 including 2022 actuals

Table 6
Integration CapEx Investments Schedule

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	Total	
		(a)	(b)	(c)	(d)	(e)	(f)	
	CapEx							
1	Business Development & Regulatory		0.6	2.0			2.6	
2	Customer Care	6.7	27.7	32.0	0.8		67.3	
3	Distribution Operations	11.3	7.1	19.0	19.8	17.0	74.2	/u
4	Energy Services	3.6	3.7	8.0	5.6	3.0	23.9	/u
5	Engineering & STO		0.2	2.0	0.3		2.5	
6	Other Functions						-	/u
7	Overheads	7.6	11.0				18.6	
8	Total Annual CapEx	29.1	50.4	63.0	26.5	20.0	189.0	/u
9	Net Book Value (included in rate base forecast)						119.0	/u

Notes:

(1) Distribution Ops: Work Mgmt. phases utility work, construction, meters, customer attachment

(2) CapEx is reflective of year spent

(3) Overheads are included at the project level starting in 2021

(4) Associated impact of NBV reflected in the 2024 Test Year revenue requirement is $28 million

(5) Revisions to Other Functions to reflect deferral of GTA East and West Projects

b) Please see the in-service Table 6 below including 2022 actuals.

Table 6

Integration CapEx Investments Schedule - In-Service

		2019		2020		2021		2022		2023		Total		
Line No.	Particulars ($ millions)	In Service Actuals	Dep'n	In Service Actuals	Dep'n	In Service Actuals	Dep'n	In Service Actuals	Dep'n	2023 Bridge Year	Dep'n	In Service Actuals	Dep'n	
		(a)		(b)		(c)		(d)		(e)		(f)		
	In-Service													
1	Business Development & Regulatory			0.1		3.0	0.3		0.8		0.8	3.1	1.9	
2	Customer Care			14.1	0.7	54.9	4.4	0.8	8.1		8.2	69.8	21.4	/u
3	Distribution Operations	15.5		-	6.1	15.3	7.5	18.3	7.6	34.8	13.0	83.9	34.2	/u
4	Energy Services	2.1	0.2	0.9	0.9	0.3	0.9	17.8	5.1	4.4	5.3	25.5	12.4	/u
5	Engineering & STO					1.9					0.1	1.9	0.1	/u
6	Overheads	1.2		3.6								4.8	-	
7	Total Annual CapEx	18.8	0.2	18.7	7.7	75.4	13.1	36.9	21.6	39.2	27.4	189.0	70.0	/u

Notes:

(1) Distribution Ops: Work Mgmt. phases utility work, construction, meters, customer attachment

(2) Overheads are included at the project level starting in 2021

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedules 1-8

Question(s):

Enbridge Gas has submitted a detailed energy transition plan in this application. It has also sought approval for an Energy Transition Technology Fund ("ETTF") of $5 million per year, totaling $25 million over the 2024 to 2028 period to "advance and accelerate research, development, and commercialization of low-carbon technologies."

Please elaborate on how the energy transition plan and the ETTF (if approved) would help to mitigate the risks from energy transition faced by Enbridge Gas, specifically for the 2024-2028 period.

Response:

Enbridge Gas's Energy Transition Plan (ETP) and its associated objectives and proposals, as provided at Exhibit 1, Tab 10, Schedule 6, are intended to ensure continued progress towards Ontario's 2030 GHG emission reductions target, while managing pathway uncertainty; please see response at Exhibit I.1.10-STAFF-39 for further discussion on this topic. In addition, Enbridge Gas has taken many steps to minimize the risk of stranded assets, please see response at Exhibit I.1.10-STAFF-34 part a) for further details.

The evidence related to the Energy Transition Technology Fund in Exhibit 1, Tab 10, Schedule 7 will be addressed in Phase 2 of the proceeding as noted in Enbridge Gas's February 1, 2023 letter.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 3, pp. 4-12; Exhibit 1, Tab 10, Schedule 4, pp. 2-3, Exhibit 1, Tab 10, Schedule 6, pp. 1-8.

Question(s):

Enbridge Gas describes current provincial and federal climate policies impacting Enbridge Gas (federal - methane regulations, carbon pricing, Clean Fuel Regulation; provincial - Emissions Performance Standards). Enbridge Gas provides its energy transition forecasts for number of customers and average use, and notes that historically, it has only considered climate policies that have been implemented and that in this application it is accounting for known energy transition factors and will incorporate changes as policy signals become more certain. Enbridge Gas describes emerging federal, provincial, and municipal energy transition and climate change policies.

a) Have any of the policies described as “emerging” in Exh. 1, Tab 10, Schedule 6 been directly incorporated into Enbridge Gas’s forecasts for number of customers and average use? If so, please describe.

b) Please provide a description of the approach Enbridge Gas plans to take during the rebasing term to adapt its investments and expenditures as a result of these emerging policies.

Response:

a) No, Enbridge Gas has not incorporated the referenced emerging climate policies directly into the customer forecast and average use assumptions. As summarized in Exhibit 1, Tab 10, Schedule 6, pages 8 and 12, there remains a lack of detail and certainty on how emerging government policies on all levels (federal, provincial and municipal) will be implemented; however, as provided at Exhibit 1, Tab 10, Schedule 4, page 5, Enbridge Gas has included adjustments to the customer forecasts based on market trends, including net-zero buildings in new construction, lower customer additions for replacement conversions and existing customers replacing equipment with non-gas equipment at end of life.

b) Enbridge Gas keeps abreast of emerging government policies, plans and targets as well as builder and market trends. Over the rebasing term, Enbridge Gas will continue to monitor external energy transition signals and stay informed on energy transition plans via external stakeholder engagements (i.e., with municipalities, builders, contract customers etc.). Enbridge Gas will continue to monitor and consider the following emerging trends in its future forecasting and planning:

- Emerging federal, provincial, municipal, and indigenous policies (laws, regulations, codes and standards), as well as targets and plans related to climate change and energy transition.

- Customer trends and market information obtained via engagement with customers and other stakeholders

Enbridge Gas will use these external signals as inputs into the demand forecast process as they become more certain, and they will form the basis for energy transition assumptions that are incorporated in the forecast and planning processes. As noted in Exhibit 1, Tab 10, Schedule 4, energy transition assumptions are factored into Average Use Forecast, Customer Forecast, Volume Forecast, Design Hour and Design Day for this rebasing period. Enbridge Gas will review these demand forecast elements annually, or as appropriate based on external factors, to determine if the energy transition assumptions need to be adjusted.

The demand forecast and design elements impact Enbridge Gas's Asset Management Plan, gas supply planning and rate setting, all of which impact the Company's investments and expenditures.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, pp.3-4; Exhibit 3, Tab 2, Schedule 5, p.9

Question(s):

Enbridge Gas describes its Energy Transition assumptions for average use. Enbridge Gas notes that its average use forecast includes adjustments for carbon pricing. Enbridge Gas notes that, as a result of the energy transition adjustment to the customer forecast, the 2024 Test Year general service annual volume forecast is approximately 2,899,408 cubic meters per year lower than would otherwise be the case. However, (Exhibit 3) Enbridge Gas also notes that natural gas price was not statistically significant in the residential average use forecasting model, thus was excluded as a forecasting variable.

a) Do the Energy Transition assumptions for average use described in this section (i.e., the inclusion of carbon pricing, but no inclusion of other potential factors such as future energy efficiency of codes and standards) in this section apply to both the 2024 Test Year forecast and the longer-term demand forecast through 2032 that is used to develop Enbridge Gas's Asset Management Plan (AMP)? If there are differences in the assumptions regarding average use in the longer-term forecast, please describe.

b) Please confirm that the forecasting adjustments described for carbon pricing are only used for the average use forecast for non-residential customers, i.e. the assumption is that residential average use is not affected by cost of natural gas, including the rising carbon price.

Response:

Please note that the 2,899,408 cubic meters volume reduction as a result of energy transition adjustment to the customer forecast that was stated in Exhibit 1, Tab 10, Schedule 4, pages 3 to 4, is incorrect. Please see response at Exhibit I.1.10-STAFF-31, Table 7 for the corrected data.

a) The average use forecast is used to develop Enbridge Gas's annual volume forecast, but the annual volume forecast is not used to develop Enbridge Gas's Asset Management Plan (AMP). Energy transition assumptions for average use apply to both the 2024 Test Year forecast and the longer-term annual volume forecast through 2032.

   Distribution Reinforcement Projects in the AMP include energy transition effects on customer count and design hour demand. This process informs the reinforcements identified in the AMP and is used on specific project scope and justifications. The assets in the AMP are based on the design day and the design hour forecasts.

b) Enbridge Gas initially anticipated that natural gas prices (including the rising carbon price) would affect residential average use. During the variable selection process, natural gas prices were included in all the models (5 residential and 5 non-residential models), but they were found to be statistically significant only for EGD rate zone non-residential models (3 out of 5 models). Therefore, Enbridge Gas's non-residential average use forecast is partially affected by the cost of natural gas, including the rising carbon price but the residential average use forecast is not.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, p. 4; Exhibit 2, Tab 6, Schedule 2, Table 5.1.10-1 and Appendices A and B; Exhibit 4, Tab 2, Schedule 6, p. 18

Question(s):

In exhibits 1.10.4 and 4.2.6, Enbridge Gas proposes to conduct a Hydrogen Blending Grid Study for a total of $12 million.

In Exhibit 2.6.2, Table 5.1.10-1, Enbridge Gas proposes to conduct a Hydrogen Feasibility Study for a total of $15.5 million. In Appendix A of this exhibit, Enbridge Gas proposes to conduct a Hydrogen Feasibility Study for a total of $12 million. In Appendix B of this exhibit, Enbridge Gas proposes to conduct a Hydrogen Feasibility Study for a total of $15.5 million.

a) Please confirm that “Hydrogen Blending Grid Study” and “Hydrogen Feasibility Study” are different names for the same study. If not, please explain the differences between these two studies.

b) If question (a) is confirmed, please reconcile the cost estimates of $12 million and $15.5 million.

Response:

a) Confirmed.

b) Please see the footnote under Table 5.1.10-1 provided at Exhibit 2, Tab 6, Schedule 2, Page 75 which indicates costs reflected in this table include overhead allocation.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, pp.5-7; Exhibit 3, Tab 2, Schedule 5, p. 7; Exhibit 3, Tab 2, Schedule 6, pp. 4, 9; EB-2021-0002 Decision and Order, p.3; Enbridge Gas Home Efficiency Rebate Plus website (https://www.enbridgegas.com/residential/rebates-energy-conservation/home-efficiency-rebate-plus)

Question(s):

Enbridge Gas discusses the energy transition assumptions embedded in its customer additions forecast (Table 2). Enbridge Gas notes that based on market trends, Enbridge Gas assumed that on a voluntary basis, a portion of new buildings would not be serviced by natural gas, and a portion of existing natural gas customers would choose to replace heating equipment reaching end of life with non-gas alternatives.

a) Please provide more detail on the market trends that informed Enbridge Gas's energy transition assumptions in Table 2.

b) Please provide a copy of the 2020 Residential: Single Family Natural Gas End Use Study used to inform the assumption that 94% and 82% of customers were likely to replace their equipment with natural gas space and water heating equipment, respectively.

c) How much emphasis is Enbridge Gas placing on these study results in developing its energy transition assumptions in Table 2, given that certain key variables, such as the cost of natural gas including the carbon price, were different in 2020 than they are in 2023 and will be at the end of this rebasing period?

d) Please describe how Enbridge Gas has considered the rising carbon price in its consideration of forecasts as they relate to customer additions.

e) Has Enbridge Gas considered the likely impact of building code changes (including the new Canadian Energy model code discussed in Exhibit 3) on its assumptions for the portion of new buildings that would be serviced by natural gas?

f) Why does Enbridge Gas assume that the rate of customer additions for replacement customers (existing homes and businesses who switch from other energy sources to natural gas) does not begin to decline until 2030?

g) The Home Efficiency Rebate Plus program (a modified version of the Government of Canada's Greener Homes Grant program that is delivered by Enbridge Gas in Ontario and is available to Enbridge Gas customers and non-Enbridge Gas customers) provides significant incentives for existing buildings to install electric space heating systems (ground source and air source heat pumps) intended to service the entire home. Per the OEB's EB-2021-0002 decision, Enbridge Gas customers are not required to remain an Enbridge Gas customer after participating in this program. What assumptions regarding the impact of the Home Efficiency Rebate Plus program are included in Enbridge Gas's customer additions forecast for replacement customers (existing homes and businesses who switch from other energy sources to natural gas) and its forecast for shrinkage of existing Enbridge Gas customers?

h) Has Enbridge Gas performed any sensitivity analysis regarding how its forecast of year-over-year change to average number of customers (customer additions minus shrinkage customers) would impact its forecast spending in the 2023-2032 AMP?, e.g. what would be the impact on capital requirements in the AMP of a 25%, 50%, or 100% reduction in net new customers, relative to the forecast?

Response:

a) For the new construction customer addition forecast, Enbridge Gas reviewed trends related to net-zero energy ready buildings and types of heating systems being installed. Enbridge Gas relied upon results published in the Canadian Home Builders' Association May 2021 Report "CHBA Net Zero Home Labelling Program Summary Report – 2020" to assess the percentage of homes in Ontario voluntarily being built to a net-zero standard as of 2020, and the percentage of net-zero homes being supplied with natural gas. A summary version of this report is provided in response at Attachment 1.

   For the existing customer forecast, Enbridge Gas reviewed the 2020 Residential Single Family Natural Gas End Use study provided in response at Exhibit I.1.10-GEC-7, Attachment 3, for results related to the fuel source of new furnaces and water heaters and the number of natural gas appliances.

   Enbridge Gas did not have market trend reports related to existing buildings that are not currently serviced by natural gas, and therefore assumed that conversions to natural gas from this segment would continue at the current pace until 2029. Enbridge Gas assumed that buildings in this segment were likely to be heated by oil or propane, older, and less energy efficient, and would require extensive retrofitting prior to fuel-switching to electricity in preference of natural gas. For further details please see the response at Exhibit I.1.10-GEC-7 parts a) and c) iii.

b) Please see response at Exhibit I.1.10-GEC-7, Attachment 3.

c) Enbridge Gas considers the market trend information referred to in response to part a) representative of the best available information at the time of forecasting. Enbridge Gas's forecasting process is undertaken on an annual basis to reflect changes in market conditions and energy and climate related policies and programs and the impact they may have on forecasting variables. Enbridge Gas will continue to review market trends and policies to update forecasting inputs and energy transition assumptions.

   As an example, in the 2022 Enbridge Brand Health Study provided in response at Exhibit I.1.6-SEC-83 Attachment 1, pages 84 to 86, residential customers were asked whether they expected their natural gas use to change in the next 5 years. The majority of respondents indicated they expect their natural gas use to remain the same (71%), while 14% indicated they expect their natural gas use to increase. Among those who indicated they expect their natural gas use to increase, 41% indicated they were likely to purchase more natural gas appliances. With respect to the 13% who expect their natural gas use to decrease, only 25% of these respondents indicated it was likely to be due to fuel-switching to another energy source. Most indicated a decrease would likely be due to being more energy efficient (e.g., temperatures setback and more efficient equipment).

d) Enbridge Gas's proposed customer additions forecast is explained in detail at Exhibit 3, Tab 2, Schedule 6. The customer additions forecast does not consider carbon pricing. Carbon pricing is taken into account in the average use forecast.

e) With respect to anticipated changes in the building code and the customer forecast, Enbridge Gas assumed that by 2030 the Ontario Building Code (harmonized with the National Energy Code of Canada for Buildings) would require new buildings to be built according to a net-zero energy ready standard, and that gas equipment (I.e., fueled by hydrogen or methane or mixtures) would be available for use in net-zero energy ready buildings. It was assumed that 10 percent of builders in 2030 would voluntarily choose not to service these buildings with gas. Enbridge Gas used the results of the 2021 CHBA Net-Zero labelling report referred to in response to part a) and interpolated a percentage between 2023 and 2030 to estimate the percentage of new construction buildings that would voluntarily choose not to connect to the gas grid and extended this trend beyond 2030. Please see response at Exhibit I.1.10-STAFF-31 Attachment 1, Table 5 for the adjustment to the new construction customer addition forecast.

f) Please see response at Exhibit I.1.10-GEC-7 part a) and c) iii.

g) Details of the Home Efficiency Rebate Plus (HER+) Program were not sufficiently known at the time of forecasting, so it was not specifically considered in Enbridge Gas's energy transition assumptions related to existing customers, as described in the response to a) above; however, the HER+ Program represents an example of the type of incentives that Enbridge Gas assumed may be available that would encourage voluntary fuel switching amongst existing customers starting in 2026.

h) Enbridge Gas has not completed any sensitivity analysis regarding how its forecasted year-over-year changes to the average number of customers would impact its forecasted AMP spending. Enbridge Gas did not complete this sensitivity analysis because to obtain a meaningful understanding of how greater reductions, like 25% or 50%, would impact the forecasted AMP spending, Enbridge Gas would require in-depth knowledge of where the greater reductions would occur in its service area and when. These customer reductions would also need to be considered in tandem with any other energy transition related changes that might occur. For example, a reduction in customer numbers will not necessarily translate into a corresponding reduction in capital spending. For example, in a situation where hydrogen blending is increased in the distribution system, the increased volume of gas required could at least partially offset the impact of reduced customer numbers. Please see response at Exhibit.I.2.6-Staff-70b for additional discussion on the possible energy transition scenarios that could impact the AMP in various ways. Without this more in-depth understanding of where and when future changes to customer additions and the system could occur, a sensitivity analysis would be of little to no value in understanding changes to AMP spending. The second reason that Enbridge Gas did not complete this sensitivity is, even if Enbridge Gas wanted to guess as to where the reductions might occur, completing this analysis would require the hydraulic models to be updated or rebuilt with the geo-specific and timing information to understand which growth projects and/or IRP projects would not be required. This process is time consuming and would take several months to complete.

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Ontario Homes Labelled within the CHBA Net Zero Home Labelling Program

as of December 31, 2020

Label	Pilot	2017	2018	2019	2020	Total
Net Zero Home	14	6	9	96	10	135
Net Zero Ready Home	0	3	4	106	185	298
Total	**14**	**9**	**13**	**202**	**195**	**433**

Heating System Configuration	ON
ASHP + Natural Gas Furnace	321
ASHP + Electric Furnace	93
ASHP + Baseboard	9
Combo/Domestic Hot Water	4
Gas Furnace	3
Ground Source Heat Pump System	2
Other	1
	433

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, pp.7-8

Question(s):

Enbridge Gas describes its Energy Transition assumptions in the volume forecast. Enbridge Gas notes that, as a result of the energy transition adjustment to the customer forecast, the 2024 Test Year general service annual volume forecast is approximately 2,899,408 cubic meters per year lower than would otherwise be the case.

a) Does the reduction in 2024 Test Year annual volume of 2,899,408 cubic meters per year in the general service annual volume forecast in the 2024 Test Year forecast derive only from the changes in number of customers, or does the volume reduction also incorporate the impact of the carbon pricing assumptions on average annual use?

b) Please provide the annual volume forecast for each year through 2032 for general service customers that is used in the longer-term demand forecast used to develop Enbridge Gas's AMP, and the change in annual volumes in these years due to Energy Transition assumptions.

c) Please provide the annual greenhouse gas emissions associated with the annual volume forecast for general service customers for each year through 2032, first assuming these volumes are 100% conventional natural gas, and second, incorporating Enbridge Gas's assumptions as to what percentage of volumes may come from lower-carbon supply sources (please provide the rationale for these assumptions).

Response:

a) The reduction in the 2024 Test Year annual volume of 2,889,408 cubic meters in the general service annual volume forecast is incorrect. Please see response at Exhibit I.1.10-STAFF 31 for the corrected impact. The volume reduction incorporates both the changes in the number of customers and the impact of the carbon pricing assumption on the average use forecast.

b) Enbridge Gas's AMP does not use the annual volume forecast. However, please see response at Exhibit I.1.10-STAFF 31, Table 1 for the annual volume forecast for each year through 2032 and Table 7 for the change in annual volumes in these years due to energy transition assumptions.

c) Using the data provided at Exhibit I.1.10-STAFF 31, Tables 1 and 7, the annual greenhouse gas (GHG) emissions associated with the annual volume forecast for general service customers, before accounting for energy transition assumptions, are shown in Table 1, column (a) below. The emissions savings associated with the adjustments in annual volumes in these years due to energy transition assumptions is shown in Table 1, column (b) below. The annual GHG emissions associated with the annual volume forecast for general service customers while incorporating change due to energy transition assumptions is shown in Table 1, column (c) below. The GHG emissions shown in Table 1 are based on the assumption that 100% of the gas volumes are natural gas.

Table 1
Annual GHG emissions of volume forecast for general service customers (million tCO_2e)

Year	Annual GHG Emissions	Emissions Savings	Annual GHG Emissions including Energy Transition
	(a)	(b)	(c) = (a)-(b)
2024	30.317	0.002	30.315
2025	30.312	0.004	30.308
2026	30.306	0.012	30.287
2027	30.298	0.024	30.274
2028	30.282	0.027	30.256
2029	30.261	0.029	30.232
2030	30.233	0.031	30.202
2031	30.275	0.032	30.243
2032	30.313	0.035	30.279

The emissions reductions as a result of energy transition assumptions shown in Table 1 above include forecast natural gas volume reductions as a result of number of customers and the impact of the carbon pricing assumption on the average use forecast.

Table 2 shows forecast GHG emissions of general service customers incorporating Low Carbon Energy Project (LCEP) Phase 1 estimated hydrogen volumes at continuous 2% blend. Impacts of RNG supply has not been included. This issue will be addressed in Phase 2 of the proceeding in accordance with the OEB's Decision on Issues List dated January 27, 2023. Please see response at Exhibit I.1.10-ED-40 for gaseous fuel consumption forecast assumptions. Enbridge Gas assumes that GHG emissions based on the annual volume forecast for general service customers will be lower than shown on the forecast below once assumptions on RNG and LECP Phase 2 can be included.

Table 2
Annual GHG emissions of volume forecast for general service customers incorporating LCEP Phase 1 area hydrogen blend of 2% (million tCO2e)

Year	Emissions
2024	30.315
2025	30.308
2026	30.287
2027	30.274
2028	30.256
2029	30.232
2030	30.201
2031	30.243
2032	30.278

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, pp.7-8; Exhibit 3, Tab 2, Schedule 7, pp. 3-4; EB-2021-0002, Decision and Order (DSM Decision), November 15, 2022; 2021 Natural Gas Demand Side Management Annual Verification Report, November 1, 2022, p.4 & p.6.

Question(s):

Enbridge Gas discusses adjustments to its volume forecast to adjust for future demand side management (DSM) Plan activities.

a) Please discuss why Enbridge Gas's 2024 Test Year DSM volumes are lower than the verified first year natural gas savings from 2021 DSM programs in the 2021 Annual Verification Report (93,890,052 m3).

b) Please discuss how the proposed 2023 Bridge Year and 2024 DSM Test Year forecast volumes reconcile with the recently approved DSM plan that includes materially increased DSM budgets and correspondingly higher natural gas savings targets beginning in 2023 and increasing in 2024 and 2025.

c) Please discuss what updates or assumptions, if any, Enbridge Gas has made or is proposing to its load forecasting methodology (including the longer-term demand forecast through 2032 used to develop Enbridge Gas's AMP) in response to the OEB's DSM Decision that includes expectations from the OEB that DSM programs result in more meaningful reductions in overall natural gas sales volumes, and that approved DSM programs show progress in reducing overall natural gas usage while delivering benefits to ratepayers, including

- The establishment of an End-of-Term Natural Gas Reduction Incentive (p. 3 of DSM Decision) during the current DSM plan term that runs to the end of 2025;

- The expectation that "the next DSM Plan will result in meaningful natural gas savings each year between 2026 and 2030 … the OEB expects that, at a minimum, the level of natural gas savings from DSM programs during the next multi-year term will be the equivalent of at least 0.6% of sales in 2026, 0.8% of sales in 2027 and 1.0% of sales in each year from 2028 through to the end of

2030, relative to the prior year on a weather normalized basis." (p. 4 of the DSM Decision).

Response:

a) The 2021 DSM results are not in scope for this proceeding and are based on two distinct scorecard structures for each of the legacy utilities. Additionally, the 2021 amounts are on an actual basis rather than forecast and reflect differences in baselines, among a multitude of other differences. The 2024 Test Year DSM volumes were based on the DSM Plan filing (EB-2021-0002) that contains a fully amalgamated scorecard structure, differing programming, differing scorecard metrics among many other differences. The referenced 2024 Test Year volumes also encompass only general service rate classes, whereas the referenced DSM annual verification report covers the entire DSM portfolio and all rate classes. The DSM Plan was approved by the OEB in November 2022 in EB-2021-0002. The Company declines to respond to reconciliation requests from previous year's actuals results for DSM as this would be duplicative of the DSM Plan proceeding.

b) Please see response to part c).

c) The Company has received several similar interrogatories related to the OEB DSM Plan Decision in EB-2021-0002 ("DSM Plan decision").

   The DSM Plan Decision included increases in the proposed DSM Plan budget in the 2023 through 2025 term. The increased budget is reflected in the updated evidence filed March 8, 2023.

   Some interested parties queried 'materially higher' forecasts between the DSM Plan decision and the original DSM Plan and/or questioned the impact of this on this Application and/or requested updates to the evidence based on changes to the volume forecast. The Company does not plan to update the evidence to reflect the impact of differing DSM Plan targets on the volume forecast, as the change is not material as described below.

   The Company notes that on an annual target volume basis the difference between the 2024 as-filed DSM Plan target and the DSM Plan Decision 2024 target is cumulatively 8.8 million m^3 across all rate classes. The total general service normalized volumes for 2024 Test Year as provided at Exhibit 3, Tab 2, Schedule 7, Attachment 1 are 15,688 million m^3. The total contract volumes for the 2024 Test Year as shown at Exhibit 3, Tab 2, Schedule 8, Attachment 1 are an additional 12,235 million m^3. Any differences between the DSM Plan decision and the original DSM Plan are not materially higher in the context of this proceeding. Similarly, any differences in such a forecast for 2025 (the end of the DSM term) using the as filed DSM Plan targets versus the DSM Plan decision would also not be material.

Some interested parties queried the impact of direction for the next DSM Plan filing for the 2026 to 2030 term, including questioning if the Rebasing Application 'complies' with the DSM Plan Decision, stating that the OEB required reductions in net natural gas volumes starting in 2026. The Company interprets the DSM Plan Decision as laying out a target for the Company to consider, among myriad other items, as an input into the next DSM Plan Application, and one that has yet to be adjudicated by the OEB. The DSM Plan Decision specifically notes an expectation that the Stakeholder Advisor Group would provide input into the next DSM Plan Application. It also sets a clear expectation that an achievable potential study ("future APS") should be performed by OEB Staff and is to be a key input into the next DSM Plan. The future APS is required to have various scenarios, at 0.5%, 1.0% and 1.5% percentage system throughput reduction, among other things. This indicates that the OEB expects to consider a wide range of outcomes in the next DSM Plan proceeding. In any event, the OEB has not reviewed the budgets associated with the next DSM Plan. Enbridge Gas views the direction from the DSM Plan Decision for the future DSM Plan term as preliminary and subject to future determinations, not as something the Company needs to 'comply' with in this application.

Some interested parties queried the impact of the OEB-approved End of Term Natural Gas Reduction Incentive ("EOTNGRI") in the DSM Plan Decision and whether this would have any impact on the load forecasting methodology or long-term forecast that underpins the Company's Asset Management Plan. The EOTNGRI is a shareholder incentive mechanism intended to align the Company's interests with broad policy goals. The EOTNGRI does not change the OEB-approved targets for the DSM Plan term. The Company also notes that there many factors beyond the DSM Plan that would have an impact on the EOTNGRI, including but not limited to: economic growth in the province, the number of new customers that choose to attach to the gas system, the amount of gas-fired generation used during the measured period, significant changes in usage by large gas volume consumers and population growth within the Company's franchise areas. Finally, the EOTNGRI covers the period from 2022 to 2025 and there is no indication presently that this incentive mechanism will persist beyond this period, so making any additional adjustments to longer-term forecasts or methodologies would be premature.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, p.8

Question(s):

Enbridge Gas notes that it did not make any additional energy transition-related adjustments in the distribution contract market forecast and that energy transition impacts are inherent and specific to customers in the proposed forecast methodology.

a) Please confirm that the methodology used to develop customer and volume forecasts for the distribution contract market extends beyond the 2024 test year to cover the length of the AMP (through 2032).

b) Please provide the annual volume forecast for each year through 2032 for distribution contract customers that is used in the longer-term demand forecast used to develop Enbridge Gas's AMP.

c) Please provide the annual greenhouse gas emissions associated with these volumes, first assuming these volumes are 100% conventional natural gas, and second, incorporating Enbridge Gas's assumptions as to what percentage of volumes may come from lower-carbon supply sources (please provide the rationale for these assumptions).

d) For the power generation sector specifically, what are the annual volume forecasts for each year through 2032? Has Enbridge Gas considered how provincial or federal energy transition policy (e.g, the federal government's commitment that Canada's electricity generation would be net zero by 2035) are likely to impact these volumes?

Response:

a) Confirmed.

b) The annual volume forecast for distribution contract market customers for 2023 to 2028 has been provided in Attachment 1. The annual volume forecast is not used to develop Enbridge Gas's AMP.

c) The annual greenhouse gas emissions associated with the volume forecast for distribution contract market customers for 2023 to 2028 are provided in Table 1. Enbridge Gas has not estimated the percentage of low carbon gas within the distribution contract forecast volumes.

Table 1
Greenhouse gas emissions associated with forecast volume for distribution contract market customers (million tCO_2e)

Line No.	Year	Annual Emissions
	(a)	(b)
1	2023	23.24
2	2024	23.64
3	2025	24.07
4	2026	25.68
5	2027	25.69
6	2028	25.67

d) The annual volume forecast for natural gas fired power generation for 2023 to 2028 has been provided in Table 2. These volumes are based on customer specific forecasts developed as part of the distribution contract market as provided at Exhibit 3, Tab 2, Schedule 8.

Enbridge Gas is following the development of the proposed federal Clean Electricity Regulations (CER), which is intended to drive progress towards a net-zero electricity grid by 2035. To support affordability and reliability while achieving net zero, Environment and Climate Change Canada's (ECCC's) Proposed Frame for Clean Electricity Regulation[1] has proposed a technology neutral and not prescriptive approach, which will allow solutions such as carbon capture and storage, co-firing fossil fuels with low-carbon fuels or switching to low-carbon fuels to achieve compliance. Additionally, ECCC is also proposing to allow units commissioned before 2025 to become subject to the CER at the end of their prescribed life, at which point it is proposed they may be able to provide backup to variable renewable electricity under certain conditions that have yet to be determined. This may allow units to operate using un-abated natural gas past 2035. Based on the proposed compliance flexibility, and ability for natural gas fired power generation to operate

[1] Government of Canada. (2022, July 26). Proposed Frame for the Clean Electricity Regulations. https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/publications/proposed-frame-clean-electricity-regulations.html

beyond 2035, Enbridge Gas is currently unable to forecast potential impacts of the CER on power generation sector volumes.

Table 2

Ontario Natural Gas Fired Power Generation
Forecast Annual Consumption (10^3m^3)

Line No.	Year	Annual Volumes
	(a)	(b)
1	2023	2,126,871
2	2024	2,256,083
3	2025	2,426,083
4	2026	2,426,083
5	2027	2,426,083
6	2028	2,426,083

Forecast Throughput Volumes - Distribution Contract Market Sales & T-Service

Line No.	Particulars (10^3m^3)	Utility	2023 Bridge Year	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
			(a)	(b)	(c)	(d)	(e)	(f)
1	Rate 100	EGI	28,090	27,429	26,755	26,067	25,366	24,656
2	Rate 110	EGI	1,074,372	1,068,281	1,062,070	1,055,734	1,049,271	1,042,732
3	Rate 115	EGI	386,039	381,873	377,624	373,290	368,870	364,397
4	Rate 125	EGI	824,971	824,971	824,971	824,971	824,971	824,971
5	Rate 135	EGI	55,486	52,646	49,751	46,797	43,784	40,735
6	Rate 145	EGI	15,331	15,714	15,704	15,695	15,685	15,675
7	Rate 170	EGI	322,426	323,254	322,232	321,189	320,126	319,050
8	Rate 200	EGI	186,602	188,852	188,852	188,852	188,852	188,852
9	Rate 300	EGI	-	-	-	-	-	-
10	Rate 315	EGI	-	-	-	-	-	-
11	Total - EGD Rate Zone		2,893,316	2,883,020	2,867,958	2,852,594	2,836,924	2,821,068
12	Rate M4	EGI	598,163	593,900	596,394	598,685	600,768	602,727
13	Rate M7	EGI	749,542	789,737	829,883	869,819	909,542	949,136
14	Rate M9	EGI	90,073	90,073	90,073	90,073	90,073	90,073
15	Rate M10	EGI	329	-	-	-	-	-
16	Rate 20	EGI	839,751	929,101	922,915	916,841	910,647	904,379
17	Rate 100	EGI	1,036,696	1,076,378	1,073,870	1,071,447	1,068,975	1,066,473
18	Rate T1	EGI	434,564	431,289	428,970	426,604	424,191	421,749
19	Rate T2	EGI	4,962,964	5,005,643	5,210,603	6,028,438	6,020,961	5,995,875
20	Rate T3	EGI	249,200	249,200	249,200	249,200	249,200	249,200
21	Rate M5	EGI	60,802	59,493	58,956	58,409	57,851	57,286
22	Rate 25	EGI	111,374	126,831	127,215	127,215	127,215	127,215
23	Rate 30	EGI	-	-	-	-	-	-
24	Total - Union Rate Zone		9,133,458	9,351,645	9,588,079	10,436,731	10,459,421	10,464,114
25	Total Contract Volume		12,026,774	12,234,665	12,456,037	13,289,325	13,296,345	13,285,182

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, p. 8 and Exhibit 3, Tab 2, Schedule 6, p. 8

Question(s):

The 2024 customer additions forecast reflects an adjustment of 321 fewer general service customer additions as a result of energy transition assumptions. As a result of the energy transition adjustment to the customer forecast, the 2024 Test Year general service annual volume forecast is approximately 2,899,408 cubic metres per year lower than would otherwise be the case.

Please state the assumptions and explain the methodology used to reflect an adjustment of 321 fewer general customer additions in the 2024 customer forecast and the resulting reduction of approximately 2.9 million cubic metres in the 2024 general service annual volume forecast.

Response:

The adjustment of 321 fewer customer additions in the 2024 Test Year customer forecast is correct; however, the resulting reduction of 2.9 million cubic meters to the 2024 Test Year general service annual volume forecast is incorrect.

The volumetric impact of 321 fewer customer additions is a reduction to volumes of 1,062,274 cubic meters. Please see Attachment 1, Tables 3 and 7 for a summary of the aggregated energy transition adjustments to forecasted customers and volumes for the period of 2024 to 2032. Underlying assumptions used to determine the energy transition adjustments to customers and volumes are detailed in Table 2. Each assumption has a separate impact on customers and volumes and these individual impacts are included in Attachment 1, Tables 4 to 6 and Tables 8 to 10 respectively.

Existing customers (unlocks), new construction customer additions, replacement customer additions and average use forecast used to determine the related energy transition assumptions impact are included in Attachment 1, Tables 11 to 14.

Also included in Attachment 1, Table 1 is Enbridge Gas's annual volume forecast (general service) for the period of 2024 to 2032.

A summary of the tables included in Attachment 1 is provided below:

Table	**Table of Contents**
1	Enbridge Gas's General Service Annual Volumes Forecast: 2024-2032
2	List of Energy Transition Assumptions used in Enbridge Gas's 2024-2032 Annual Volume Forecast
3	Enbridge Gas's Energy Transition Impacts on Customers **based on all assumptions*
4	Enbridge Gas's Energy Transition Impacts on Customers **based on Assumption 1*
5	Enbridge Gas's Energy Transition Impacts on Customers **based on Assumption 2*
6	Enbridge Gas's Energy Transition Impacts on Customers **based on Assumption 3*
7	Enbridge Gas's Energy Transition Impacts on Volumes **based on all assumptions*
8	Enbridge Gas's Energy Transition Impacts on Volumes **based on Assumption 1*
9	Enbridge Gas's Energy Transition Impacts on Volumes **based on Assumption 2*
10	Enbridge Gas's Energy Transition Impacts on Volumes **based on Assumption 3*
11	Enbridge Gas's Customers (Existing Customers) used for Assumption 1
12	Enbridge Gas's New Construction Customer Additions used for Assumption 2
13	Enbridge Gas's Replacement Customer Additions used for Assumption 3
14	Enbridge Gas's Average use (m3)
15	Customer Additions ET Assumptions Impact
16	Customer Additions Before ET Assumptions
17	Customer Additions After ET Assumptions

Table 1
Enbridge Gas Annual Volume (1)

Line No.	Particulars ($10^6 m^3$)	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
1	EGD																					
2	Residential	4,609.0	4,640.2	4,707.0	4,684.2	4,688.7	4,851.5	4,871.7	4,904.4	5,011.9	4,953.5	4,936.5	4,984.2	5,001.0	5,018.0	5,032.1	5,047.0	5,060.6	5,073.2	5,083.9	5,094.2	5,103.2
3	Commercial	3,955.2	3,966.7	4,118.7	4,083.8	3,940.1	4,121.0	4,383.1	4,299.6	4,191.4	4,089.4	4,192.5	4,245.6	4,234.2	4,204.9	4,175.5	4,147.9	4,120.4	4,093.3	4,065.2	4,070.0	4,074.5
4	Industrial	661.9	641.8	671.6	657.2	638.9	641.5	654.6	624.1	553.2	529.7	483.3	573.8	561.5	548.4	534.8	522.4	509.9	496.9	484.0	475.5	467.1
5	Union																					
6	Residential	2,867.3	2,904.2	2,950.6	2,895.9	2,914.4	3,018.5	3,059.3	3,129.7	3,155.1	3,090.8	3,104.2	3,165.2	3,178.2	3,191.7	3,202.4	3,213.7	3,223.8	3,233.1	3,241.5	3,249.5	3,256.9
7	Commercial	1,917.7	1,954.4	2,026.2	1,996.4	1,991.9	2,062.2	2,074.9	2,136.5	2,097.8	1,980.1	2,032.1	2,195.6	2,213.9	2,224.0	2,232.5	2,241.0	2,249.6	2,257.7	2,265.7	2,274.4	2,282.6
8	Industrial	481.6	483.6	482.1	493.7	478.3	499.8	509.8	510.9	474.9	461.2	462.5	510.7	499.4	497.8	496.2	494.9	493.2	491.2	489.1	487.0	485.0
9	EGI																					
10	Residential	7,476.4	7,544.4	7,657.6	7,580.1	7,603.2	7,870.0	7,930.9	8,034.1	8,166.9	8,044.3	8,040.8	8,149.4	8,179.3	8,209.7	8,234.5	8,260.7	8,284.4	8,306.3	8,325.4	8,343.8	8,360.1
11	Commercial	5,872.9	5,921.1	6,144.9	6,080.2	5,932.0	6,183.1	6,458.0	6,436.1	6,289.1	6,069.5	6,224.5	6,441.2	6,448.1	6,428.8	6,408.0	6,388.9	6,369.9	6,351.0	6,330.9	6,344.4	6,357.1
12	Industrial	1,143.5	1,125.4	1,153.7	1,150.9	1,117.2	1,141.3	1,164.5	1,135.1	1,028.1	990.9	945.9	1,084.5	1,060.9	1,046.2	1,031.1	1,017.3	1,003.0	988.1	973.1	962.5	952.1
13	Total General Service Volumes	14,492.8	14,590.9	14,956.3	14,811.2	14,652.4	15,194.4	15,553.4	15,605.3	15,484.1	15,104.8	15,211.2	15,675.0	15,688.2	15,684.7	15,673.6	15,667.0	15,657.4	15,645.3	15,629.4	15,650.7	15,669.2

Note:
(1) Normalized to 2024 proposed HDDs; Actual for 2012-2022, Forecast for 2023-2032

Table 2
List of Energy Transition Assumptions used in Enbridge Gas 2024-2032 Annual volume forecast

Assumption #1 #1-Fuel switching: Apply to unlocks (existing customers). Starts from 2026. Reduction as seen below:
total customers*(0.05*0.1*0.1)

Year	Description	Adj.factor
2026	Existing Customers (Unlocks)*0.0005	0.0005
2027	Existing Customers (Unlocks)*0.0005	0.0005
2028	Existing Customers (Unlocks)*0.0005	0.0005
2029	Existing Customers (Unlocks)*0.0005	0.0005
2030	Existing Customers (Unlocks)*0.0005	0.0005
2031	Existing Customers (Unlocks)*0.0005	0.0005
2032	Existing Customers (Unlocks)*0.0005	0.0005

Assumption #2 Voluntarily Net Zero and NG Ban: Apply to new construction customer additions. Starts from 2023. F Description

Year	Description	Adj.factor
2024	2024-new construction customer adds*0.009	0.009
2025	2025-new construction customer adds*0.019	0.019
2026	2026-new construction customer adds*0.029	0.029
2027	2027-new construction customer adds*0.048	0.048
2028	2028-new construction customer adds*0.065	0.065
2029	2029-new construction customer adds*0.081	0.081
2030	2030-new construction customer adds*0.10	0.10
2031	2031-new construction customer adds*0.11	0.11
2032	2032-new construction customer adds*0.13	0.13

Assumption #3 Conversion to NG: Apply to Replacement customer adds. Starts from 2030. Reduction as seen below:

Year	Description	Adj.factor
2030	2030-replacement cust adds*0.1	0.1
2031	2031-replacement cust adds*0.1	0.1
2032	2032-replacement cust adds*0.1	0.1

NOTE: AMP uses only Customer additions related assumptions (Assumption 2 and 3)

Table 3
Enbridge Gas Energy Transition Impacts on Customers (based on All Assumptions from Table 4, 5 and 6)

Line No.	Sector	2024 Test Year (a)	2025 Forecast (b)	2026 Forecast (c)	2027 Forecast (d)	2028 Forecast (e)	2029 Forecast (f)	2030 Forecast (g)	2031 Forecast (h)	2032 Forecast (i)
1	EGD									
2	Residential	188	388	1,678	2,035	2,314	2,575	3,176	3,296	3,568
3	Apartment	0	0	4	5	5	5	5	5	6
4	Commercial	8	16	105	118	130	139	184	186	195
5	Industrial	0	0	3	3	3	3	3	3	3
6	Union South									
7	Residential	97	202	872	1,064	1,219	1,365	1,561	1,636	1,797
8	Commercial	7	14	65	77	86	92	100	100	106
9	Industrial	0	0	4	4	4	4	5	5	5
10	Union North									
11	Residential	19	38	228	261	287	309	365	372	394
12	Commercial	2	3	21	23	26	27	29	29	30
13	Industrial	0	0	0	0	0	0	0	0	0
14	EGI									
15	Residential	304	628	2,778	3,360	3,820	4,249	5,102	5,304	5,760
16	Commercial	9	17	90	105	117	124	134	134	141
17	Industrial	8	16	109	122	134	143	189	191	199
18	Total	321	661	2,977	3,587	4,071	4,516	5,425	5,629	6,100

Table 4
Enbridge Gas Energy Transition Impacts on Customers (based on Assumption 1)

Line No.	Sector	2024 Test Year (a)	2025 Forecast (b)	2026 Forecast (c)	2027 Forecast (d)	2028 Forecast (e)	2029 Forecast (f)	2030 Forecast (g)	2031 Forecast (h)	2032 Forecast (i)
1	EGD									
2	Residential			1,101	1,111	1,122	1,131	1,141	1,150	1,158
3	Apartment			4	4	4	4	4	4	4
4	Commercial			81	81	82	82	83	83	84
5	Industrial			3	3	3	3	3	3	3
6	Union South									
7	Residential			568	573	578	583	587	592	596
8	Commercial			45	46	46	46	46	46	47
9	Industrial			3	3	3	3	3	3	3
10	Union North									
11	Residential			172	173	174	175	176	176	177
12	Commercial			16	16	16	16	16	16	16
13	Industrial									
14	EGI									
15	Residential			1,841	1,857	1,874	1,889	1,904	1,918	1,931
16	Apartment									
17	Commercial			142	66	66	66	66	66	67
18	Industrial			6	84	85	85	86	86	87
19	Total			1,989	2,007	2,025	2,040	2,056	2,070	2,085

Table 5
Enbridge Gas Energy Transition Impacts on Customers (based on Assumption 2)

Line No.	Sector	2024 Test Year (a)	2025 Forecast (b)	2026 Forecast (c)	2027 Forecast (d)	2028 Forecast (e)	2029 Forecast (f)	2030 Forecast (g)	2031 Forecast (h)	2032 Forecast (i)
1	EGD									
2	Residential	188	388	577	924	1,192	1,444	1,727	1,843	2,114
3	Apartment				1	1	1	1	1	2
4	Commercial	8	16	24	37	48	57	67	70	79
5	Industrial									
6	Union South									
7	Residential	97	202	304	491	641	782	945	1,018	1,177
8	Commercial	7	14	20	31	40	46	54	54	59
9	Industrial			1	1	1	1	2	2	2
10	Union North									
11	Residential	19	38	56	88	113	134	159	168	191
12	Commercial	2	3	5	7	10	11	13	13	14
13	Industrial									
14	EGI									
15	Residential	304	628	937	1,503	1,946	2,360	2,831	3,029	3,482
16	Commercial	9	17	25	39	51	58	68	68	75
17	Industrial	8	16	25	38	49	58	69	72	81
18	Total	321	661	987	1,580	2,046	2,476	2,968	3,169	3,638

Table 6
Enbridge Gas Energy Transition Impacts on Customers (based on Assumption 3)

Line No.	Sector	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	EGD									
2	Residential							308	303	296
3	Apartment									
4	Commercial							34	33	32
5	Industrial									
6	Union South									
7	Residential							29	26	24
8	Commercial									
9	Industrial									
10	Union North									
11	Residential							30	28	26
12	Commercial									
13	Industrial									
14	EGI									
15	Residential							367	357	346
16	Apartment									
17	Commercial							34	33	32
18	Industrial									
19	Total							401	390	378

Table 7
Enbridge Gas Energy Transition Impacts on Volumes (based on All Assumptions from Table 8,9 and 10)

Line No.	Particulars (m^3)	2024 Test Year (a)	2025 Forecast (b)	2026 Forecast (c)	2027 Forecast (d)	2028 Forecast (e)	2029 Forecast (f)	2030 Forecast (g)	2031 Forecast (h)	2032 Forecast (i)
1	EGD									
2	Residential	435,574.5	892,461.7	3,832,402.3	4,616,206.7	5,214,781.5	5,766,402.5	6,383,528.2	6,621,899.8	7,197,448.7
3	Commercial	159,506.5	315,722.3	2,052,871.2	2,962,337.3	3,160,719.6	3,299,277.3	3,473,371.3	3,522,431.5	3,829,648.2
4	Industrial									
5	Union									
6	Residential	253,804.4	522,525.1	2,379,242.5	2,852,890.5	3,227,893.0	3,572,104.3	3,966,634.3	4,133,658.2	4,510,327.6
7	Commercial	213,388.3	284,393.3	1,533,583.0	1,803,082.0	2,090,048.3	2,081,362.7	2,357,059.3	2,358,488.4	2,394,404.0
8	Industrial			65,003.0	65,090.3	65,166.7	65,233.1	81,637.3	81,727.8	81,825.3
9	EGI									
10	Residential	689,378.9	1,414,986.8	6,211,644.8	7,469,097.2	8,442,674.5	9,338,506.8	10,350,162.5	10,755,558.1	11,707,776.3
11	Commercial	372,894.8	600,115.6	3,586,454.2	4,765,419.3	5,250,767.9	5,380,640.1	5,830,430.6	5,880,919.8	6,224,052.2
12	Industrial			65,003.0	65,090.3	65,166.7	65,233.1	81,637.3	81,727.8	81,825.3
13	Total Energy Transition impacted Volumes	1,062,274	2,015,102	9,863,102	12,299,607	13,758,609	14,784,380	16,262,230	16,718,206	18,013,654

Note:
(1) Volumes normalized to 2024 Test Year Forecast heating degree days

Table 8
Enbridge Gas Energy Transition Impacts on Volumes (based on Assumption 1)

Line No.	Particulars (m^3)	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	EGD									
2	Residential			2,514,586	2,520,199	2,528,515	2,532,738	2,539,489	2,544,332	2,547,263
3	Apartment				540,684	530,775	521,107	511,545	506,498	501,470
4	Commercial			1,583,643	1,569,535	1,575,189	1,562,067	1,568,114	1,567,403	1,585,922
5	Industrial									
6	Union South									
7	Residential			1,236,540	1,241,181	1,245,903	1,250,708	1,253,443	1,258,382	1,261,255
8	Commercial			1,000,014	1,003,022	1,023,595	944,170	979,848	981,032	954,382
9	Industrial			48,752	48,818	48,875	48,925	48,982	49,037	49,095
10	Union North									
11	Residential			362,779	363,332	363,938	364,597	365,291	363,957	364,729
12	Commercial			44,559	62,055	88,185	96,511	113,477	112,905	120,984
13	Industrial			0	0	0	0	0	0	0
14	EGI									
15	Residential			4,113,904	4,124,713	4,138,356	4,148,043	4,158,223	4,166,670	4,173,247
16	Commercial			1,044,573	1,605,761	1,642,555	1,561,788	1,604,870	1,600,435	1,576,836
17	Industrial			1,632,396	1,618,352	1,624,064	1,610,992	1,617,096	1,616,439	1,635,017
18	Total			6,790,873	7,348,826	7,404,976	7,320,823	7,380,189	7,383,545	7,385,100

Table 9
Enbridge Gas Energy Transition Impacts on Volumes (based on Assumption 2)

Line No.	Particulars (m^3)	2024 Test Year (a)	2025 Forecast (b)	2026 Forecast (c)	2027 Forecast (d)	2028 Forecast (e)	2029 Forecast (f)	2030 Forecast (g)	2031 Forecast (h)	2032 Forecast (i)
1	EGD									
2	Residential	435,575	892,462	1,317,817	2,096,007	2,686,266	3,233,664	3,843,731	4,077,568	4,650,185
3	Apartment				135,171	132,694	130,277	127,886	126,625	250,735
4	Commercial	159,506	315,722	469,228	716,948	922,062	1,085,827	1,265,827	1,321,906	1,491,522
5	Industrial									
6	Union South									
7	Residential	213,361	442,014	661,810	1,063,560	1,381,702	1,677,622	2,017,894	2,163,906	2,490,766
8	Commercial	195,385	257,521	444,451	675,949	890,083	944,170	1,150,257	1,151,646	1,198,054
9	Industrial			16,251	16,273	16,292	16,308	32,655	32,691	32,730
10	Union North									
11	Residential	40,443	80,511	118,114	184,816	236,351	279,177	330,007	347,413	393,577
12	Commercial	18,003	26,873	44,559	62,055	88,185	96,511	113,477	112,905	120,984
13	Industrial									
14	EGI									
15	Residential	689,379	1,414,987	2,097,741	3,344,384	4,304,318	5,190,463	6,191,632	6,588,888	7,534,529
16	Commercial	213,388	284,393	489,010	873,176	1,110,962	1,170,958	1,391,620	1,391,176	1,569,773
17	Industrial	159,506	315,722	485,478	733,220	938,354	1,102,135	1,298,482	1,354,597	1,524,252
18	Total	1,062,274	2,015,102	3,072,229	4,950,780	6,353,634	7,463,557	8,881,733	9,334,661	10,628,554

Table 10
Enbridge Gas Energy Transition impacted Volumes (based on Assumption 3)

Line No.	Particulars (m^3)	2024 Test Year (a)	2025 Forecast (b)	2026 Forecast (c)	2027 Forecast (d)	2028 Forecast (e)	2029 Forecast (f)	2030 Forecast (g)	2031 Forecast (h)	2032 Forecast (i)
1	EGD									
2	Residential							685,506	2,544,332	2,547,263
3	Apartment							511,545	506,498	501,470
4	Commercial							1,568,114	1,567,403	1,585,922
5	Industrial									
6	Union South									
7	Residential							1,253,443	1,258,382	1,261,255
8	Commercial							979,848	981,032	954,382
9	Industrial							48,982	49,037	49,095
10	Union North									
11	Residential							365,291	363,957	364,729
12	Commercial							113,477	112,905	120,984
13	Industrial							0	0	0
14	EGI									
15	Residential							2,304,240	4,166,670	4,173,247
16	Commercial							1,604,870	1,600,435	1,576,836
17	Industrial							1,617,096	1,616,439	1,635,017
18	Total							5,526,206	7,383,545	7,385,100

Table 11
Unlocks (Average number of Existing Customers) for Assumption 1

Line No.	Sector	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	EGD									
2	Residential			2,201,925	2,222,956	2,243,044	2,262,400	2,281,152	2,299,315	2,316,911
3	Apartment			7,365	7,365	7,365	7,365	7,365	7,365	7,365
4	Commercial			161,774	162,749	163,681	164,580	165,451	166,295	167,114
5	Industrial			5,626	5,606	5,587	5,567	5,548	5,528	5,509
6	Union South									
7	Residential			1,136,450	1,146,603	1,156,340	1,165,745	1,174,883	1,183,762	1,192,393
8	Commercial			90,704	91,178	91,633	92,072	92,499	92,914	93,318
9	Industrial			5,067	5,065	5,062	5,060	5,057	5,055	5,052
10	Union North									
11	Residential			343,963	345,995	347,892	349,658	351,324	352,898	354,382
12	Commercial			31,516	31,596	31,671	31,740	31,806	31,868	31,926
13	Industrial			152	152	152	152	152	152	152
14	EGI									
15	Residential			3,682,338	3,715,554	3,747,277	3,777,803	3,807,358	3,835,975	3,863,686
16	Apartment			7,365	7,365	7,365	7,365	7,365	7,365	7,365
17	Commercial			283,994	285,523	286,984	288,392	289,756	291,077	292,358
18	Industrial			10,845	10,823	10,801	10,779	10,757	10,735	10,713
18	Total			3,984,542	4,019,265	4,052,427	4,084,339	4,115,236	4,145,152	4,174,122

Table 12
New Construction Customer Adds for Assumption 2

Line No.	Sector	2024 Test Year (a)	2025 Forecast (b)	2026 Forecast (c)	2027 Forecast (d)	2028 Forecast (e)	2029 Forecast (f)	2030 Forecast (g)	2031 Forecast (h)	2032 Forecast (i)
1	EGD									
2	Residential	20,826	20,359	19,919	19,228	18,350	17,804	17,274	16,758	16,258
3	Apartment	15	15	14	14	13	13	12	12	12
4	Commercial	906	862	820	780	742	706	672	639	608
5	Industrial	2	2	2	2	2	2	2	2	2
6	Union South									
7	Residential	10,810	10,647	10,490	10,221	9,866	9,656	9,450	9,250	9,055
8	Commercial	769	730	690	652	612	574	535	494	455
9	Industrial	29	26	24	22	20	18	16	14	12
10	Union North									
11	Residential	2,094	2,004	1,922	1,830	1,734	1,660	1,592	1,528	1,466
12	Commercial	185	175	166	156	147	136	127	119	109
13	Industrial									
14	EGI									
15	Residential	33,730	31,006	30,409	29,449	28,216	27,460	26,724	26,008	25,313
16	Commercial	969	1,592	1,510	1,432	1,354	1,280	1,207	1,133	1,063
17	Industrial	935	28	26	24	22	20	18	16	14
18	Total	35,634	32,626	31,945	30,905	29,592	28,760	27,949	27,157	26,390

Table 13
Replacement Customer Additions for Assumption 3

Line No.	Sector	2024 Test Year (a)	2025 Forecast (b)	2026 Forecast (c)	2027 Forecast (d)	2028 Forecast (e)	2029 Forecast (f)	2030 Forecast (g)	2031 Forecast (h)	2032 Forecast (i)
1	EGD									
2	Residential							3,082	3,029	2,979
3	Apartment									
4	Commercial							344	331	318
5	Industrial									
6	Union South									
7	Residential							293	262	235
8	Commercial									
9	Industrial									
10	Union North									
11	Residential							298	278	260
12	Commercial									
13	Industrial									
14	EGI									
15	Residential							3,673	3,569	3,474
16	Apartment									
17	Commercial							344	331	318
18	Industrial									
19	Total							4,017	3,900	3,792

Table 14
Average Use

Line No.	Particulars (m^3)	2024 Test Year (a)	2025 Forecast (b)	2026 Forecast (c)	2027 Forecast (d)	2028 Forecast (e)	2029 Forecast (f)	2030 Forecast (g)	2031 Forecast (h)	2032 Forecast (i)
1	EGD									
2	Residential	2,317	2,300	2,284	2,268	2,254	2,239	2,226	2,212	2,200
3	Apartment			137,698	135,171	132,694	130,277	127,886	126,625	125,367
4	Commercial	19,938	19,733	19,551	19,377	19,210	19,050	18,893	18,884	18,880
5	Industrial			94,952	92,809	90,685	88,587	86,514	85,232	83,969
6	Union South									
7	Residential	2,200	2,188	2,177	2,166	2,156	2,145	2,135	2,126	2,116
8	Commercial	27,912	18,394	22,223	21,805	22,252	20,525	21,301	21,327	20,306
9	Industrial		16,226	16,251	16,273	16,292	16,308	16,327	16,346	16,365
10	Union North									
11	Residential	2,129	2,119	2,109	2,100	2,092	2,083	2,076	2,068	2,061
12	Commercial	9,001	8,958	8,912	8,865	8,819	8,774	8,729	8,685	8,642
13	Industrial									

Table 15

Enbridge Gas Energy Transition impacts on Customer Additions (based on Assumptions 2 and 3 only; Table 5 and 6) (1)

Line No.	Sector	2024 Test Year (a)	2025 Forecast (b)	2026 Forecast (c)	2027 Forecast (d)	2028 Forecast (e)	2029 Forecast (f)	2030 Forecast (g)	2031 Forecast (h)	2032 Forecast (i)
1	EGD									
2	Residential	188	388	577	924	1,192	1,444	2,035	2,146	2,410
3	Apartment	0	0	0	1	1	1	1	1	2
4	Commercial	8	16	24	37	48	57	101	103	111
5	Industrial	0	0	0	0	0	0	0	0	0
6	Union South									
7	Residential	97	202	304	491	641	782	974	1,044	1,201
8	Commercial	7	14	20	31	40	46	54	54	59
9	Industrial	0	0	1	1	1	1	2	2	2
10	Union North									
11	Residential	19	38	56	88	113	134	189	196	217
12	Commercial	2	3	5	7	10	11	13	13	14
13	Industrial	0	0	0	0	0	0	0	0	0
14	EGI									
15	Residential	304	628	937	1,503	1,946	2,360	3,198	3,386	3,828
16	Commercial	17	33	49	76	99	115	169	171	186
17	Industrial	0	0	1	1	1	1	2	2	2
18	Total	321	661	987	1,580	2,046	2,476	3,369	3,559	4,016

Note:
(1) Used for AMP.

Table 16
Customer Additions Before Energy Transition Assumptions (Actual and Forecast) (1)

Line No.	Sector	2020 Actual (a)	2021 Actual (b)	2022 Estimate (c)	2023 Bridge Year (d)	2024 Test Year (e)	2025 Forecast (f)	2026 Forecast (g)	2027 Forecast (h)	2028 Forecast (i)	2029 Forecast (j)	2030 Forecast (k)	2031 Forecast (l)	2032 Forecast (m)
1	EGD													
2	Residential	25,124	25,711	25,312	24,751	24,336	23,823	23,335	22,585	21,653	20,938	20,356	19,787	19,237
3	Apartment	19	17	16	16	15	15	14	14	13	13	12	12	12
4	Commercial	1,277	1,541	1,472	1,405	1,342	1,281	1,223	1,168	1,115	1,064	1,016	970	926
5	Industrial	2	14	2	2	2	2	2	2	2	2	2	2	2
6	Union South													
7	Residential	12,387	11,696	11,630	11,615	11,454	11,245	11,042	10,728	10,335	10,027	9,789	9,561	9,343
8	Commercial	901	650	849	809	769	730	690	652	612	574	535	494	455
9	Industrial	15	42	31	32	29	26	24	22	20	18	16	14	12
10	Union North													
11	Residential	3,435	2,555	2,813	2,698	2,580	2,447	2,324	2,195	2,064	1,938	1,844	1,756	1,673
12	Commercial	206	154	202	193	185	175	166	156	147	136	127	119	109
13	Industrial	3	2	2	(1)	0	1	1	1	1	1	1	1	1
14	Enbridge Gas													
15	Residential	40,946	39,962	39,754	39,063	38,370	37,515	36,701	35,508	34,052	32,904	31,989	31,104	30,253
16	Commercial	2,403	2,362	2,539	2,423	2,311	2,201	2,093	1,990	1,887	1,787	1,690	1,595	1,502
17	Industrial	20	58	35	33	31	29	27	25	23	21	19	17	15
18	Total	43,369	42,382	42,328	41,519	40,712	39,745	38,821	37,523	35,962	34,712	33,698	32,716	31,770

Notes:
(1) Exludes community expansion and energy transition assumptions.

Table 17
Customer Additions After Energy Transition Assumptions (Forecast) (1)

Line No.	Sector	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast
		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	EGD												
2	Residential				24,148	23,435	22,758	21,661	20,461	19,494	18,321	17,641	16,827
3	Apartment				15	15	14	13	12	12	11	11	10
4	Commercial				1,334	1,265	1,199	1,131	1,067	1,007	915	867	815
5	Industrial				2	2	2	2	2	2	2	2	2
6	Union South												
7	Residential				11,357	11,043	10,738	10,237	9,694	9,245	8,815	8,517	8,142
8	Commercial				762	716	670	621	572	528	481	440	396
9	Industrial				29	26	23	21	19	17	14	12	10
10	Union North												
11	Residential				2,561	2,409	2,268	2,107	1,951	1,804	1,655	1,560	1,456
12	Commercial				183	172	161	149	137	125	114	106	95
13	Industrial				0	1	1	1	1	1	1	1	1
14	Enbridge Gas												
15	Residential				38,066	36,887	35,764	34,005	32,106	30,544	28,791	27,718	26,425
16	Commercial				2,294	2,168	2,044	1,914	1,788	1,672	1,521	1,424	1,316
17	Industrial				31	29	26	24	22	20	17	15	13
18	Total				40,391	39,084	37,834	35,943	33,916	32,236	30,329	29,157	27,754

Notes:
(1) exludes Community Expansion and includes Energy Transition Assumptions

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, pp.8-11

Question(s):

Enbridge Gas describes energy transition assumptions used for design hour and design day.

a) Please provide more details or cross-references as to how the peak hour trends from the ETSA Reference Case Scenario were used to develop the design hour adjustment factors in Table 3, and how these factors incorporate impacts from future DSM programing, carbon pricing and natural gas commodity pricing, building performance and appliance efficiency improvements for existing customers.

b) Please confirm that these adjustments were applied only to the forecasts of design hour and design day demand, not the annual volume forecasts.

Response:

a) Please see response at Exhibit I.1.10-SEC-20.

b) Confirmed. The adjustment factors derived from the ETSA Reference Case scenario were only applied to the design hour forecast, which are used to inform design day forecast. No direct adjustment factors were applied to the design day forecasts. The annual volume forecast did not apply the design hour demand adjustment factors derived from the ETSA Reference Case scenario.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, pp.13-14

Question(s):

Enbridge Gas notes that changes to its design hour process and inclusion of energy transition factors resulted in reduced system needs and fewer reinforcements, resulting in a reduction of approximately $66 million excluding overheads, to the Distribution Reinforcement Capital forecast in the current AMP relative to the previously filed AMP.

Please provide more details on these reductions; e.g., which potential projects were avoided, deferred, or downsized, and how did the changes to the design hour process and inclusion of energy transition factors specifically contribute to these changes in the AMP?

Response:

The sum of the changes to design hour process and inclusion of energy transition factors resulted in the elimination of some previously identified projects including but not limited to:

- York Region Reinforcement (Phase 1-5) for approximately $52.5 million.
- Penetanguishene Reinforcement for approximately $12.1 million.
- Thornton Reinforcement for approximately $11.1 million.

The harmonization of the design hour demand process provided at Exhibit 4 Tab 2 Schedule 3 combined with the energy transition factors provided at Exhibit 1 Tab 10 Schedule 4 had the result of reducing the peak hour demand forecast, as shown in Exhibit 1, Tab 10, Schedule 4, Figure 3: Effects of Energy Transition Assumptions on the Design Hour Demand. As a result, previously identified projects were no longer required or the required in service date was deferred.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, p. 13-14, 18-19, Exhibit 1, Tab 15, Schedule 1, p. 1

Question(s):

Enbridge Gas discusses how the AMP, including the growth asset class incorporates energy transition assumptions. Enbridge Gas notes the increased risk of stranded assets from energy transition and has proposed changes to its deemed capital structure. Enbridge Gas further requests approval of its harmonized customer connection policies.

a) Please describe how Enbridge Gas has considered and attempted to mitigate the risks of stranded assets associated with the proposed capital expenditures identified in its AMP (particularly growth-related capital expenditures including customer connections and distribution/transmission system reinforcement/expansion projects, but also considering system renewal expenditures to extend the service life of assets), related to uncertainty in future volumes or number of customers arising from the energy transition.

b) In Enbridge Gas's opinion, should ratepayers bear 100% of the cost recoveries related to stranded assets?

c) Has Enbridge Gas considered whether the proposal to increase Enbridge Gas's equity ratio may work at cross-purposes to the intent of managing energy transition risk, by increasing rates and potentially increasing the risk of customers exiting the natural gas system?

d) Has Enbridge Gas given consideration to adjustments to its customer connection policies to mitigate the risk of stranded assets associated with new customer connections who may leave the natural gas system before Enbridge's investment is recovered, e.g., by reducing the customer revenue horizon, requiring greater upfront customer contributions, eliminating the free service allowance for residential infills, introducing exit fees for new customers, etc.? If so, please provide details.

Response:

a) Enbridge Gas's proposed 2024 to 2028 AMP capital expenditures are predicated on fulfilling its obligation to (1) maintain a safe and reliable system, (2) connect customers based on OEB-approved connection policies and (3) implement IRP alternatives where technically and economically feasible. Enbridge Gas acknowledges that there exists some uncertainty about how the energy transition will unfold in Ontario; however, this does not absolve Enbridge Gas from the aforementioned obligations, especially when, despite pathway uncertainty, a project's underlying need/constraint has a high degree of certainty (e.g., minimum five-year demand forecast) and /or there is an absence of other technically or economically feasible alternatives.

   Enbridge Gas has taken many steps to mitigate the risk of stranded assets associated with the proposed capital expenditures within and beyond the five-year regulatory plan period. These include:

   - Completing an Energy Transition Scenario Analysis (ETSA) to understand the impacts of energy transition and the associated climate policies on natural gas demand in Enbridge Gas's distribution system.

   - Commissioning the Pathways to Net Zero Emissions in Ontario Study, conducted by Guidehouse to understand how Enbridge Gas's system could play a role in a net-zero future. The study built upon the ETSA work and found that a Diversified scenario achieves net zero with significant savings and more reliability, relative to an electrification scenario. The Diversified scenario would also increase the need for pipeline infrastructure to deliver large quantities of low carbon fuels like hydrogen and RNG. Please see Exhibit 1, Tab 10, Schedule 5.

   - Ongoing review and incorporation of energy transition assumptions into the demand forecasting process for new construction and existing customers replacing gas appliances and updates to annual and peak demand for gas. Please see Exhibit 1, Tab 10, Schedule 4, Table 2.

   - Ongoing updates to the asset management plan to respond to a changing pace of energy transition and to ensure that facilities projects' underlying needs/constraints (e.g., minimum five-year demand forecast) have a high degree of certainty when they are brought forward for approval. Please see Exhibit 1, Tab 10, Schedule 4, paragraph 37.

   - Incorporation of the IRP framework into the asset management process to defer or avoid new infrastructure, where possible, due to uncertainty related to energy transition. Please see Exhibit 1, Tab 10, Schedule 4, paragraph 43.

- Enhancements to the Distribution Integrity Management Program will allow the Company to further optimize its vintage steel main replacement program. Please see Exhibit 1, Tab 13, Schedule 3.

- Ongoing monitoring of Federal/ Provincial/Municipal policy across all sectors, including buildings, industry, transportation, and electricity generation and policies supporting energy efficiency, electrification, low carbon fuels and CCUS.

- As provided at Exhibit 1, Tab 10, Schedule 6, paragraph 106, Enbridge Gas will seek to understand how the Ontario government's Energy Transition and Electrification panel work will inform the Ontario government's energy transition policy and consequently the long-term viability of Enbridge Gas's assets. The Company has highlighted to the panel, the resiliency, reliability and future value of Ontario's 150,000 kms of underground gas storage, transmission and distribution assets in relation to the future cost of providing equivalent resiliency and reliability from a largely above ground electric transmission and distribution system. Enbridge Gas supports the panel's focus on integrating gas and electricity system planning and believes in the prudence of programs like the Ontario government's Clean Home Heating program that offers incentives for installation of heat pumps with smart controls in gas heated homes.

b) Yes. It is Enbridge Gas's view that the company should fully recover the costs of prudently invested capital. As provided in response at Exhibit I.1.10-SEC-28, Enbridge Gas has shown that in 2021, $16 billion of invested capital in the gas storage, transmission and distribution system delivers over four times the peak capacity delivered by the $25 billion invested in the electricity distribution system. The *current* unit cost of invested capital to deliver peak capacity in the form of natural gas is a quarter of that for electricity. Also, the underground gas system is more resilient than the largely above ground electricity system in Ontario.

   Enbridge Gas has invested shareholder capital to serve its customers under a regulatory compact that allows the Company to earn a fair rate of return and for the recovery of prudently invested capital through the rates charged to its customers. Enbridge Gas expects its underground storage, transmission and distribution assets to be used or useful for the foreseeable future due to their current capacity to deliver vast amounts of energy annually and on a peak basis, inherent resiliency and the low cost of connecting to the gas system.

   Enbridge Gas expects to fully recover from its customers the cost of prudently invested long-lived capital and operating and maintenance costs of providing safe, reliable and affordable energy to them. Increasing the fixed charges to connect to the system as proposed in this Application will provide cost recovery even if the amount of natural gas consumed is gradually displaced by non-emitting electricity.

Should the government institute a policy mandating disconnection from the gas system, the Company expects that it will accelerate recovery of its invested capital through regulatory measures such as higher depreciation rates and other tools including cost allocation changes to reflect a changing customer mix over time.

c) Enbridge Gas's perspective is that the increase in equity thickness mitigates the risk of investors attributing higher risk premiums with consequential impacts on the Company's cost of capital and more significant impact on customer rates.

d) Enbridge Gas is currently not experiencing a trend towards customers leaving the system nor does it have information suggesting that existing customers intend to leave the system. As noted above, Enbridge Gas is supportive of hybrid heating technologies which can reduce customers' annual GHG emissions by pairing non-emitting electricity with natural gas use to meet peak heating demands. Enbridge Gas's proposed connections policies, including the free service allowance for in-fills are established in such a manner as to ensure compliance with E.B.O 188 and the underlying principle that new customer revenues are sufficient to support their costs and do not impact the rates of existing customers. In addition, feasibility parameters such as the revenue horizon are set out in E.B.O 188 Section 2.2 Specific Parameters.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1
2019 Achievable Potential Study, APS (https://www.ieso.ca/2019-conservation-achievable-potential-study)
Federal Clean Building Strategy Discussion Paper:
https://www.nrcan.gc.ca/sites/nrcan/files/engagements/green-building-strategy/CGBS%20Discussion%20Paper%20-%20EN.pdf

Question(s):

The Posterity Group study provided by Enbridge Gas (p. 42, Reference Scenario) includes assumptions related to the Greenhouse Gas Pollution Pricing Act schedule as \$20/tonne CO2e in 2019 rising to \$58.58/tonne C02e in 2023. The study also includes assumptions related to the Natural Gas Commodity Price being 11.75¢/m3 in 2019 rising to 15.90 ¢/m3 by 2038 as well as the DSM Budget of \$132 million being held constant. The Posterity Group Reference Case follows the volume and account forecast provided by Enbridge Gas, which reflects 2019 enforced codes and standards.

a) Please provide rationale for each of the above noted assumptions in the Reference Case, given established DSM budgets for 2023 onwards, regular updates to the building code, significantly higher commodity costs since 2019, and established increases to the federal carbon prices after 2023. If the reference case was not meant to reflect established understanding related to DSM budgets for 2023 onwards, regular updates to the building code, significantly higher commodity costs since 2019, and established increases to the federal carbon prices after 2023 of current reality, please explain why it was included in this study.

b) Please describe how the impacts of existing and announced federal and municipal policy and programs, including promotion of electrification and energy efficiency, such as the Federal Canadian green building strategy, have been considered in the reference case. If they have not been considered, please explain why not.

Response:

The following response was provided by Posterity Group:

a) The objective of the Reference Case scenario was to forecast gas consumption from 2020 to 2038 based on exogenous conditions that follow a ‘business-as-usual’ scenario, that adheres to enshrined laws and regulations (policy environment) and where historical trends continue similarly into the future. The scenario allows comparison of Steady Progress, Diversified Portfolio, Electricity Centric and ETI scenarios to a ‘business-as-usual’ scenario. The various scenarios are meant to capture a range of possible changes to DSM budgets, updates to building code, changes to commodity costs, and changes to the federal carbon price trajectory that could occur in the future.

At the time the Reference Case analysis was completed, it reflected Enbridge Gas’s approved forecast methodology. The ETSA study base year is 2019 and was the most recent complete year of billing data when the modeling was developed. The volume forecast that informed the reference case was also Enbridge Gas’s most current forecast at the time the analysis was completed. Account totals and energy intensities in the base year are adjusted to match the forecasted account and consumption growth provided by Enbridge Gas.

Enbridge Gas’s forecast included assumptions about DSM budget, building codes, commodity costs and carbon prices as outlined in Exhibit 1, Tab 10, Schedule 5, Attachment 1, pages 42 to 45. At the time, these assumptions reflected enshrined laws and regulations as of October 2020, and ‘business-as-usual’ trends. Specifically:

i) Established DSM budgets for 2023 onwards

DSM budget for 2023 onwards had not been established at the time the Reference Case scenario was developed. DSM budgets included in the reference case represent a continuation of current activity (as of 2019).

ii) Regular updates to the building code

The Reference Case volume forecast reflected building codes and standards that were being enforced at the time Enbridge Gas developed the forecast (as of 2019).

iii) Significantly higher commodity costs since 2019

The Reference Case volume forecast reflected the commodity cost forecast estimate that was current when Enbridge Gas developed the forecast (as of 2019).

iv) Established increases to the federal carbon prices after 2023

The Reference Case volume forecast reflected the carbon price forecast estimate that was current when Enbridge Gas developed the forecast (as of 2019). At the time, Canada's Minimum National Carbon Pollution Price Schedule did not extend beyond 2022.

b) Existing enforced policies and programs (current as of 2019) were included in the Reference Case. The Reference Case scenario does not include announced policies or programs that are not enshrined in law or regulation, as they would not be considered 'business-as-usual'. Please refer to part a) for details on the Reference Case scenario.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1

Question(s):

The Posterity Group study provided by Enbridge Gas (p. 19-20, Price Elasticity) includes an explanation that price elasticity is only used to adjust consumption of natural gas in response to price changes of natural gas and carbon price, but that price elasticity considerations did not influence demand for Renewable Natural Gas (RNG), hydrogen or carbon capture and storage (CCS). Prices of RNG, hydrogen and natural gas with carbon capture were not used as factors that change consumption of these fuels.

a) Please provide rationale for use of elasticity of natural gas demand for each sector based on these historical studies, including one study dating back to 1997, given commodity and carbon costs context being significantly different today.

b) Please explain whether any sensitivity analysis was conducted on these elasticity assumptions. If yes, provide and describe the results. If not, please explain why not and please provide a qualitative explanation of the impact of significantly different elasticity rates than used in this study.

c) Please explain the rationale for not considering consumer price elasticity for RNG, hydrogen, and CCS in any scenario, given that the prices of these options are likely to impact adoption by customers.

Response:

The following response was provided by Posterity Group:

a) The elasticity values used are based on the best research currently available. Should new research be undertaken and published, these values will be updated.

b)
i) Please explain whether any sensitivity analysis was conducted on these elasticity assumptions

We did not conduct such a sensitivity analysis in this work.

ii) If not, please explain why not and please provide a qualitative explanation of the impact of significantly different elasticity rates than used in this study. While a sensitivity analysis on the price elasticity assumptions was not conducted, carbon price and natural gas commodity price did vary depending on the scenario.

Increasing the sensitivity by 10% has exactly the same effect in the Navigator model as increasing the change in energy cost by 10%. Please see response at Exhibit I.1.10-SEC-34 which explains how fuel switching is modelled using "own-price" elasticity assumptions.

For example:

- If we assume a long-run elasticity of -0.2, and the energy price rises by 50%, our modelling approach forecasts consumption will go down by 10%, by the target year
- If the price change increases by 10% of its original value (a 55% increase instead of a 50% increase), our modelling approach forecasts consumption will go down by 11%.
- If instead of increasing the price change from 50% to 55%, the elasticity is adjusted from -0.2 to -0.22, the modelling approach forecasts consumption will go down by 11%.
- The sensitivity analysis for both would be duplicative.

c) We do not have any information suggesting that the consumer price elasticity of demand for these fuels would be different from the elasticity for natural gas. In the scenarios where these fuels play a large role, part of the scenario narrative is that they do so because their cost is attractive relative to other energy options. Because the future costs of these fuels are uncertain, particularly in the scenarios where they play a large part, we did not consider price elasticity in determining how much of them would be included.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1
2019 Achievable Potential Study, APS (https://www.ieso.ca/2019-conservation-achievable-potential-study)

Question(s):

The Posterity Group study provided by Enbridge Gas includes the following:

- Customer account assumptions for all scenarios (p. 42 of study) in which the Reference Case is calibrated to Enbridge Gas' account forecast which provides growth rates by rate class which are mapped to the sectors in the model as follows: Residential: ~1% annual growth; Commercial: 0.1-0.4% annual growth; and Industrial: decline by 0.7% from 2019-2021 and hold constant from 2022-2038.

- Assumptions around fuel-switching in Electricity-Centric Model (p. 43 of study) as follows: Policy driven fuel switching for Residential/Commercial sectors: New residential and commercials will not connect to the gas grid starting in 2026 and water/space heating in existing buildings will be replaced at equipment turnover rate; space and water heating will be served by Air-source heat pump (ASHP) without gas back-up; and Non-mandated electrification of some industrial end-uses in some sectors as equipment will be replaced.

- In the Electricity Centric scenario (p. 69), annual volume decreases by 22% by 2030 and by 52% by 2038 relative to 2019. Increased electrification of space and water heating, high stringency codes and standards, high carbon pricing, and high DSM spending all lower volumes of gaseous fuels.

a) The 2019 APS found that 62% of natural gas use was in commercial and residential buildings in 2019 (page 12 of 2019 APS). Please explain why the estimated decline in natural gas use is 52% in 2038, given all scenarios anticipate growth in the number of residential and commercial customers, but a declining number of industrial customers.

b) Given heat pumps provide both heating and cooling, was consideration given to replacement of air conditioners with heat pumps, which could also reduce natural gas consumption if those heat pumps are used for heating (i.e. hybrid heating)? If yes, how? If not, why not?

c) Were cold climate heat pumps assumed to be required for all space and water heating? If yes, why? If not, in what circumstances would they be installed?

Response:

The following response was provided by Posterity Group:

a) As stated on Exhibit 1, Tab 10, Schedule 5, Attachment 1, page 69, the 52% decline in the Electricity Centric scenario is caused by the following modeling assumptions: "Increased electrification of space and water heating, high stringency codes and standards, high carbon pricing, and high DSM spending all lower volumes of gaseous fuels." Please see Exhibit 1, Tab 10, Schedule 5, Attachment 1, pages 42-45 for the detailed input assumptions used to model the Electricity Centric scenario. Of these, the critical driver with the most impact is non-price driven fuel switching. The model is configured so that after 2025 new residential and commercial buildings won't connect to the gas grid, and water and space heating equipment in existing buildings will be replaced with electric equipment. In the industrial sector, it is assumed that after 2029 no new gas-fired equipment is permitted for HVAC and Process Heating (Water and Steam), as detailed in the table on Exhibit 1, Tab 10, Schedule 5, Attachment 1, page 114. As existing equipment for these end uses reaches the end of its effective useful life in the existing buildings or plants, 100% of it must be replaced by electric equipment. The effect of these assumptions accounts for the largest part of the 52% reduction.

b) This study was focused on modeling impacts only on Enbridge Gas's system. In scenarios where there was fuel switching away from natural gas to electricity, either non-price-driven or price-driven, no explicit assumption was made about what electric technology would replace the gas appliance. It is reasonable to assume heat pumps would be common replacements for the gas space heating equipment. It is also reasonable to assume that air conditioner owners who install a heat pump will not keep their air conditioners. The effects of that change do not show up in the study results because the study does not report on electricity consumption. We did not consider a situation where building owners would install a heat pump primarily as a replacement for the air conditioner, where the heat supplied is considered a by-product. As we understand the question, the heat pump would be sized for the cooling load and would be undersized for the heating load. The existing gas-fired equipment would be retained to provide heating when the heat pump is insufficient. This hybrid option was not included in the scenario developed under this study.

c) As discussed in response to part b), we made no explicit assumptions about what electric heating equipment would replace the gas appliance in scenarios with gas to electric fuel switching.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1
OEB Marginal Abatement Cost Curve: https://www.oeb.ca/industry/policy-initiatives-and-consultations/consultation-develop-regulatory-framework-natural-gas, p. 47

Question(s):

The Posterity Group study provided by Enbridge Gas includes the following:

- Customer account assumptions for all scenarios (p. 42 of study) in which the Reference Case is calibrated to Enbridge Gas's account forecast which provides growth rates by rate class which are mapped to the sectors in the model as follows: Residential: ~1% annual growth; Commercial: 0.1-0.4% annual growth; and Industrial: decline by 0.7% from 2019-2021 and hold constant from 2022-2038.
- Assumptions around fuel-switching in Electricity-Centric Model (p. 43 of study) as follows: Policy-driven fuel switching for residential/commercial sectors includes assumptions that these sectors will not connect to the gas grid starting in 2026, and water/space heating in existing buildings will be replaced at the existing equipment turnover rate; Space and water heating will be served by ASHP without gas back-up; and Non-mandated electrification of some industrial end-uses in some sectors as equipment is replaced
- In the Electricity Centric scenario (p. 69), annual volume decreases by 22% by 2030 and by 52% by 2038 relative to 2019. Increased electrification of space and water heating, high stringency codes and standards, high carbon pricing, and high DSM spending all lower volumes of gaseous fuels.
- Information related to RNG, Hydrogen and carbon capture, utilization and sequestration (CCUS) - p. 26, including
    - Renewable Natural Gas: Max: Mandated use of RNG requires about three billion cubic meters per year by 2038, which is 11% of reference case demand in 2038
    - Hydrogen (H2): Max: Hydrogen blending begins in 2025, consumption reaches 12 billion cubic meters per year in 2038, or about 14% of Reference Case demand in 2038, based on mandated hydrogen targets.

- CCUS: Carbon capture is used for all process heating and power generation in refineries, chemicals, nonmetallic minerals, primary metals, and utilities in the former Union South, phased-in between 2028 and 2037
- High: Renewable content policies build demand for RNG and H2; H2 strategy overcomes equipment H2 barriers and carbon capture and sequestration (CCS) deployed for industrial end uses/ sectors not using H2

a) The OEB's Marginal Abatement Cost Curve identified the potential for RNG production in Ontario to be 627 million m3, and in Canada, 2.4 billion m3. Please provide rationale for assuming 3 billion m3 of RNG to be available to meet Ontario natural gas demand by 2038.

b) Please provide rationale for assuming 12 billion m3 of hydrogen to be available to meet Ontario natural gas demand by 2038.

c) Please provide rationale for assuming widespread adoption of hydrogen-fueled space and water heating equipment when it can be assumed that all buildings have access to electricity and would therefore have the choice between hydrogen and electric space and water heating equipment.

d) Please provide rationale for assuming widespread adoption of CCS by 2037 given current level of technical feasibility.

e) For RNG, hydrogen, and CCS assumptions in all scenarios, please explain how uncertainty related to technical feasibility has been accounted for in comparison to decarbonization options that are currently technically feasible (e.g. electric heat pumps, energy efficiency).

Response:

The following response was provided by Posterity Group:

a-e) We view the multi-scenario modeling approach as a way to mitigate the risk of uncertainty around different critical driver assumptions. We advise our utility clients to develop plans that are robust in the face of a range of plausible scenarios, particularly in cases where future policy, prices, and economic variables are uncertain (e.g., availability and cost of low/no carbon fuels and supporting technologies and equipment). This allows utilities to develop plans that are robust in the face of a range of plausible scenarios.

i) Please provide rationale for assuming 3 billion m3 of RNG to be available to meet Ontario natural gas demand by 2038.

The maximum setting of 3 billion m3 of RNG was defined as a possible upper bound for RNG on Enbridge's system. The pace and scale of RNG supply development and availability is assumed as a response to demand creation. This upper bound assumption was provided by Enbridge Gas.

Although Posterity Group did not conduct an analysis of the feasible RNG potential in Ontario, Guidehouse's report (Exhibit 1, Tab 10, Schedule 5, Attachment 2, page 21) cites a Torchlight report that estimates Ontario's RNG potential and we note our upper bound falls within this range:

"Torchlight's report estimated that Ontario has the potential to produce around 40 PJ per year of RNG supply from wet organic wastes and up to around 240 PJ per year if agricultural residues are included."

ii) Please provide rationale for assuming 12 billion m3 of hydrogen to be available to meet Ontario natural gas demand by 2038.

The maximum setting of 12 billion m3 of hydrogen was defined as a possible upper bound for hydrogen on Enbridge Gas's system. The pace and scale of hydrogen supply development and availability is assumed as a response to demand creation. This upper bound assumption was provided by Enbridge Gas.

More detailed assumptions on the hydrogen input settings for the Diversified Portfolio Scenario (the scenario with the highest input assumptions for hydrogen) are presented in Appendix F of the report. Please see Exhibit 1, Tab 10, Schedule 5, Attachment 1, pages 113 to114.

iii) Please provide rationale for assuming widespread adoption of hydrogen-fueled space and water heating equipment when it can be assumed that all buildings have access to electricity and would therefore have the choice between hydrogen and electric space and water heating equipment.

The study has not assigned a probability or a likelihood to the Diversified Portfolio scenario occurring (the scenario with the highest input assumptions for Hydrogen) - rather it is one of several scenarios describing a possible future. Please see Exhibit 1, Tab 10, Schedule 5, Attachment 1, pages 40 to 41 for details on the Diversified Portfolio scenario narrative, and the key policies and exogenous conditions assumed.

The Diversified Portfolio scenario also implicitly assumes:

a) Innovations in electric storage (or some other supply side electric technology or resource) will occur, and this technology would be available to facilitate additional load on the electricity grid resulting from fuel switching.

b) Hydrogen-ready equipment will be available and is installed (when equipment reaches its effective useful life) for industrial end-uses that switch to hydrogen.

c) Some residential and commercial customers install hydrogen-ready equipment (when equipment reaches its effective useful life).

d) CCS technology will be available and will be retrofitted on existing equipment for some industrial end-uses.

e) Low-carbon fuels, and the technology required to upgrade and inject these fuels in the grid, will be available.

iv) Please provide rationale for assuming widespread adoption of CCS by 2037 given current level of technical feasibility.

The maximum setting for carbon capture and storage technology adoption was defined as a possible upper bound for industrial segments and end-uses served by Enbridge Gas's system. The pace and scale of CCS technology development and availability is assumed as a response to demand creation. This upper bound was provided by Enbridge Gas.

More detailed assumptions on the industrial sector CCS input settings for the Diversified Portfolio Scenario (the scenario with the highest input assumptions for CCS) are presented in Appendix F of the report. Please see Exhibit 1, Tab 10, Schedule 5, Attachment 1, page 114.

v) For RNG, hydrogen, and CCS assumptions in all scenarios, please explain how uncertainty related to technical feasibility has been accounted for in comparison to decarbonization options that are currently technically feasible (e.g. electric heat pumps, energy efficiency).

Uncertainty related to technical feasibility was accounted for by developing multiple scenarios. Please see Exhibit 1, Tab 10, Schedule 5, Attachment 1, page 39 for details on the process used to develop the scenario narratives and inputs assumptions for the study. As indicated on this page, the process is founded on the idea that "Scenarios are not about predicting the future, rather they are about perceiving futures in the present. A good scenario asks people to suspend disbelief in its stories long enough to appreciate their impact. The end result is not an accurate picture of tomorrow, but better decisions about the future." To this end, as noted in Exhibit 1, Tab 10, Schedule 5, Attachment 1, page 6, both the Electricity Centric and the Diversified scenarios assume innovation occurs. Innovation with respect to expanding non-emitting power generation and electricity storage capacity, without the benefits of gas back-ups to service peak heating needs (see narrative on Page 40) is assumed in the Electricity Centric scenario. Similarly, the Diversified scenario assumes innovation in RNG, hydrogen and CCS capacity occurs to satisfy demands realized by a renewable gas content policy.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 6, pp. 13-14

Question(s):

Enbridge Gas describes the objectives of its Energy Transition Plan and also describes how it considers an action to be a 'safe bet' action.

Please describe whether and how Enbridge Gas considered the risk of asset stranding in its objectives for its Energy Transition Plan and also describe how Enbridge Gas considered the risk of asset stranding in considering whether an action is a 'safe bet'.

Response:

The risk of asset stranding was considered in Enbridge Gas's Energy Transition Plan (ETP) objectives (Exhibit 1, Tab 10, Schedule 6, p.13), in that Enbridge Gas believes achievement of the objectives will minimize this risk.

In achieving the first ETP objective, "maintaining alignment with Ontario's energy objectives and with provincial and federal energy transition and climate change targets and policies", Enbridge Gas will minimize the risk of asset stranding. Both federal and provincial governments, through policies and discussion papers, show support for a diverse set of actions that rely on the continued use of the gas system. These diverse actions include support for energy efficiency, electrification, low-carbon fuels, and carbon capture, utilization, and sequestration (CCUS) (Exhibit 1, Tab 10, Schedule 6, p. 9).

By achieving the second ETP objective, "providing cost-effective, secure, reliable and resilient energy for customers during the transition to a low-carbon economy and once net-zero is achieved", Enbridge Gas believes its assets will remain of value and, therefore, the risk of asset stranding is minimized. It is for this reason that Enbridge Gas commissioned a study that sought to understand how net-zero goals could impact natural gas demand and what role the gas system could play in Ontario in achieving its GHG reduction targets, please see Exhibit 1, Tab 10, Schedule 5 for the study's details). The Pathways to Net-Zero Emissions for Ontario (P2NZ) Study found that both the Electrification and Diversified scenarios achieve net-zero GHG emissions by 2050, that a diversified scenario achieves significant savings as compared to an electrification scenario and that regardless of the pathway chosen to achieve net-zero, energy efficiency, RNG, hydrogen and natural gas with CCUS are required.

By achieving the third ETP objective, “supporting an orderly energy transition in Ontario”, Enbridge Gas believes that customer choice will be maximized and that no one group of customers will carry the burden of reaching net-zero. Enbridge Gas believes that achievement of this objective will require the use of the Company’s assets and, therefore, achieving this objective will mitigate the risk of asset stranding.

Finally, Enbridge Gas’s definition of a safe bet action was created with the risk of asset stranding at the forefront. It is for that reason that each proposed safe bet action not only fulfills the safe bet definition, but it also does not result in overinvesting in a particular pathway prior to the Ontario government defining its energy transition plans in more detail.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 6, p. 26

Question(s):

CCUS refers to the capture of carbon dioxide (CO2) emissions from facilities or directly from the air, which are then compressed and transported to be permanently stored in geological formations underground or to be used to create products. Enbridge Gas considers CCUS to be a “safe bet” as it is required to significantly reduce Ontario’s GHG emissions. Enbridge Gas says that studies show Ontario’s unique geology is well suited to store carbon. Enbridge Gas is not requesting OEB approval for any costs or activities related to CCUS in the current application. Enbridge Gas is completing studies to further evaluate potential subsurface CO2 storage regions in Ontario.

Will the studies being completed by Enbridge Gas compare the financial benefits for shareholders and ratepayers of CCUS to the financial benefits of conventional natural gas storage? If not, would Enbridge Gas add this comparison to the scope if its studies?

Response:

The studies that Enbridge Gas is currently completing related to CCUS do not compare the financial benefits of CCUS to conventional natural gas storage. The studies are related to the geologic feasibility of CO2 storage in Ontario. Enbridge Gas does not plan to compare the financial benefits of CO2 storage to the financial benefits of natural gas storage.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

Reference:

Exhibit 1 Tab 10 Schedule 3

Preamble:

Enbridge Gas is evaluating opportunities that can generate CFR credits which may include CNG vehicles, the voluntary RNG program and hydrogen blending. Enbridge Gas may register as a credit creator to generate, trade and sell credits under the program where participation in the CFR credit market can support the Company and its customers in adopting lower carbon solutions.

Question(s):

a) How will Enbridge use any revenue from CFR credits?

b) Has Enbridge established any oversight or governance documents related to revenue from CFR credits? If so, please provide them.

Response:

a) Where Enbridge Gas is able to prudently obtain or generate CFR credits through its regulated operations, the Company believes that any associated revenues will be to the benefit of ratepayers. The specific mechanism or mechanics of providing that benefit to ratepayers, and or to which group of ratepayers, is yet to be determined and may depend on the activities and types of CFR credits obtained.

b) Enbridge Gas is in the process of developing process and procedures related to CFR credits and does not currently have finalized documents to provide.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

Reference:

Exhibit 1 Tab 10 Schedule 6

Preamble:

Enbridge Gas has developed an ETP, including some "safe bet" actions and proposals, to recognize and incorporate, where possible, the current impacts of energy transition and to ensure that progress towards Ontario's 2030 GHG emissions reduction targets and a net-zero future can continue despite the current pathway uncertainty.

The safe bet actions that have shaped Enbridge Gas's ETP are:

a) Maximizing energy efficiency;
b) Increasing the amount of RNG in the gas supply;
c) Reducing GHG emissions from the industrial and transportation sectors via fuel 16 switching and CCUS;
d) Integrating gas and electric system planning; and
e) Supporting consumer choice and the energy transition journey.

Question(s):

a) Has Enbridge ranked the proposed "safe bet" options on the underlying economic viability of each of the options? If so, please provide the ranking?

b) If not, how does Enbridge intend to target the options that provide the most value for ratepayers?

Response:

a) Enbridge Gas has not ranked the safe bet actions as provided at Exhibit 1, Tab 10, Schedule 6.

b) Although Enbridge Gas's vision of energy transition in Ontario is a diversified pathway, as provided at Exhibit 1, Tab 10, Schedule 5, Section 3, the Company has proposed safe bet actions that support energy transition regardless of the path, that will drive near-term emissions reductions and/or will maintain pathway optionality until further clarity exists on which pathway will come to fruition. The pursuit of any one individual safe bet action in isolation from the rest will not support Ontario's progress towards net-zero and, therefore, Enbridge Gas believes that steps must be taken now to enable all of these actions as opposed to ranking and staging them. The future is uncertain and the pathway to net-zero is uncharted, investing in all of the proposed safe bet actions can reduce emissions over the 2024 to 2028 period, while maintaining optionality for serving future energy demands reliably and safely. The maintenance of optionality inherently provides value by preserving consumer choice through the energy transition.

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ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

Reference:

Exhibit 1 Tab 10 Schedule 7

Preamble:

Enbridge Gas is proposing to create an ETTF in the amount of $5 million annually, for a total of $25 million over the period of 2024 to 2028. This funding is proposed to be collected through a rate rider rather than through base rates, with a new variance account established to record variances between the amounts collected by the ETTF rate rider and actual costs incurred for ETTF initiatives. Details on the proposed regulatory treatment are provided in Section 4.

While Enbridge Gas will continue to leverage this DSM funding to develop innovative energy efficiency technologies and programming, important aspects of energy transition “safe bets” like RNG, hydrogen and CCUS also require significant technology development in the province, thus requiring meaningful funding levels. For example, while initiatives such as blending renewable content into fossil fuels and increasing production of biogas and RNG have started, the full potential of related technologies is yet to be unlocked through technology advancement on a commercial scale.

The rate rider will be a fixed monthly customer charge to be collected from in- franchise customers so that each customer contributes equally to the development of low-carbon energy technologies. The forecast amount to be collected from customers is $5 million per year, totaling $25 million over the 2024 to 2028 period. As a result, the $5 million proposed to be collected for the ETTF is incremental to the proposed 2024 revenue deficiency. Please see Exhibit 8, Tab 1, Schedule 2 for the rate design and recovery proposal of the ETTF.

The monthly bill impact of the ETTF is $0.11 per customer. Enbridge Gas’s recent customer engagement shows that the majority of customers support contributing towards an innovation and technology fund with the goal of advancing low-carbon technologies. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 16-17 for a summary of these customer engagement results.

Question(s):

a) Please provide details on how the $5 million in annual revenue will be spent.

b) Please provide details on how the $5 million in annual revenue will not target unregulated activities.

Response:

a-b) This evidence will be addressed in Phase 2 of the proceeding as noted in Enbridge Gas's February 1, 2023 letter.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

1-10-4

Preamble:

This section provides details on how Enbridge Gas has considered energy transition in the company's forecasted number of customers, average use, design day and design hour demand, and distribution contract customer demand.

Question(s):

a) Please provide Enbridge Gas' (EGD and Union combined) consolidated history and forecast of annual, design hour and design day gas demand for each year from 2018 until 2028 for the commercial, residential and industrial sectors and the whole system.

b) Please provide EGI's history and current forecast of annual, design hour and design day gas demand savings due to DSM for each year from 2018 until 2028 for the commercial, residential and industrial sectors and the whole system.

c) Please provide EGI's current forecast of annual, design hour and design day gas demand savings arising from the Energy Transition Scenario Analysis for each year from 2024 until 2028 for the commercial, residential and industrial sectors and the whole system.

d) Please file a copy of any studies estimating the potential for annual, design hour and design day gas use reductions due to ventilation heat recovery in commercial buildings conducted by EGI or which EGI is aware of.

e) Please file a copy of any studies estimating the potential for annual, design hour and design day gas use reductions due to modified unoccupied space temperature setback in commercial buildings conducted by EGI or which EGI is aware of.

f) Please file a copy of any studies estimating the potential for annual gas use reductions due to application of heat recovery chillers in commercial buildings conducted by EGI or which EGI is aware of.

g) Please file a copy of any studies or reports on year over year INCREASES in weather normalized gas use in commercial buildings, which are unexplained by known changes in building use, occupancy or operations, conducted by EGI or which EGI is aware of.

h) Please confirm that QRAM fully trues up for all variances between forecast and actual annual gas prices and volumes and that EGI does not benefit in any way financially from such variances.

Response:

a) Please see response at Exhibit I.5.3-STAFF-215 part a), Attachment 1 for the historic and forecast annual demand. Please see response at Exhibit I.1.10-GEC-11 part c) for the design hour demand prior to 2022. The design hour forecast for 2022 to 2028 is shown in response at part b) . The forecasted design day demand is not available for the years prior to 2023, only actuals are available. The total design day demand is shown in response at part b) for 2023 to 2028.

b-c) Table 1 provides the net annual, fully effective m^3 savings from DSM each year from 2018 to 2021 (actual) and forecast 2022 to 2025. Actual annual volumetric forecasts include a combination of partially effective and fully effective volumes. The current DSM Plan expires 2025, per OEB approval; any potential DSM m^3 savings after 2025 are to be determined.

Table 1
(m^3)

Line No.	Sectors (1)	2018	2019	2020	2021	2022 (2)(3)	2023 (3)	2024 (3)	2025 (3)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	19,470,732	21,354,836	19,412,509	20,132,845	18,857,170	25,031,392	26,750,005	28,127,670
2	Commercial	33,849,928	34,390,287	20,029,986	24,941,773	28,326,776	26,464,368	27,006,156	27,642,576
3	Industrial	55,235,858	59,945,704	56,796,187	49,783,283	58,712,193	62,560,792	63,792,144	65,067,986
4	Total	108,556,518	115,690,827	96,238,682	94,857,901	105,896,139	114,056,552	117,548,304	120,838,233

Notes:

(1) Sectors are based on QRAM Rate Class Sectors and not DSM sector-based reporting.

(2) 2022 results are not yet finalized. Instead, the m^3 savings at 100% target have been provided.

(3) 2023 to2025 savings are forecast based on 100% target; sectors estimated based on historical data.

Please see response at Exhibit I.1.10-STAFF 31, Attachment 1, Table 1 for the annual volume forecast for 2024 to 2028 and Table 7 for the change in annual volumes in these years due to energy transition assumptions.

The individual effects of DSM and energy transition cannot be separated for design day or design hour demand. As provided at Exhibit 4, Tab 2, Schedule 3, paragraph 51, g) ii), the design day demand accounts for a declining trend in general service use per customer, reflecting observed energy efficiency gains or processes or behavioural changes. As provided at Exhibit 1, Tab 10, Schedule 4, paragraph 29, the incorporation of design hour adjustment factors based on the ETSA reference case allowed for impacts of DSM to be accounted for along with other energy transition related impacts.

The design day demand forecast with and without energy transition assumptions applied, and the resulting delta in demand for 2023 to 2028 is shown in Table 2. Design day demand is segregated into general service and contract demand. The general service portion cannot be broken out by sector.

The design hour demand forecast with and without energy transition assumptions applied, and the resulting delta in demand for 2022 to 2028 is shown in Table 3. The design hour demand cannot be broken out by sector as the input sectoral segregation was not preserved when aggregated into a single number.

Table 2
Total Design Day Demand with and without Energy Transition Assumptions

	Before Energy Transition Assumptions			After Energy Transition Assumptions			Difference		
m3/day	General Service	Contract Rate	Total	General Service	Contract Rate	Total	General Service	Contract Rate	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
2023	154,314,452	74,130,269	228,444,721	153,507,137	74,130,269	227,637,406	(807,315)	-	(807,315)
2024	155,799,642	75,379,580	231,179,223	154,250,038	75,379,580	229,629,618	(1,549,605)	-	(1,549,605)
2025	157,196,692	77,463,080	234,659,772	154,977,790	77,463,080	232,440,871	(2,218,902)	-	(2,218,902)
2026	158,566,103	81,066,960	239,633,063	155,740,767	81,066,960	236,807,727	(2,825,336)	-	(2,825,336)
2027	159,880,699	71,298,473	231,179,172	156,514,859	71,298,473	227,813,332	(3,365,840)	-	(3,365,840)
2028	161,120,779	82,290,960	243,411,739	157,272,665	82,290,960	239,563,625	(3,848,114)	-	(3,848,114)

Table 3
Total Design Hour Demand with and without Energy Transition Assumptions

m3/hr	Before Energy Transition Assumptions	Energy Transition Assumptions in Customer Count And Demand per Customer	Difference
	(a)	(b)	(c)
2022	11,081,827	11,030,547	(51,280)
2023	11,149,588	11,032,940	(116,648)
2024	11,214,430	11,066,640	(147,790)
2025	11,279,508	11,087,961	(191,547)
2026	11,341,141	11,121,255	(219,887)
2027	11,399,188	11,148,362	(250,826)
2028	11,453,584	11,183,727	(269,856)

d) The 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study led by the IESO and the OEB included heat recovery ventilation among the measures it studied for annual electric and gas savings potential in commercial buildings.[1]

e) The 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study led by the IESO and the OEB included adaptive thermostats among the measures it studied for annual electric and gas savings potential in commercial buildings.[2] Please see ICF Canada's Final Report on Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, dated May 18, 2018, pages ES-21 to ES-22 and page 89 to 90, filed in response to procedural order No. 2 issued by the OEB for EB-2020-0091.

f) None.

g) None.

h) Confirmed. All gas supply commodity, transportation, load balancing, and inventory revaluation costs are passed through to customers without markup and Enbridge Gas does not benefit financially from any such variances between forecast and actual costs. Please see Exhibit 9, Tab 1, Schedule 2, Section 1 for the costs that are proposed to be cleared through the QRAM and the relevant deferral and variance accounts. Enbridge Gas is proposing to record variances related to gas

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[1] 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study, December 10, 2019, p.E-20, https://www.oeb.ca/sites/default/files/2019_Achievable_Potential_Study_20191218.pdf
[2] Ibid, p. 181.

supply commodity and gas supply-related transportation costs for sales service customers in the PGVA and separate variance accounts will record variances related to upstream transportation, load balancing, and inventory revaluation.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

1.10.7

Question(s):

Energy Transition Technology Fund: Please describe the proposed governance and decisionmaking process for identifying, qualifying and prioritizing potential projects and expenditures.

Response:

The evidence on Energy Transition Technology Fund (ETTF) will be addressed in Phase 2 of the proceeding as noted in Enbridge Gas's February 1, 2023 letter.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

1.10.2 page 4

Preamble:

Enbridge Gas's system consistently fulfills these critical energy system needs because of its:

c) System storage capacity, via underground storage facilities and via 'linepack'10 in the gas transmission system.

Question(s):

a) Please provide EGI's total gas storage capacity in terms of volume Mm3 and days of supply under design day conditions.

b) Please describe how much of this capacity is allocated/available to the commercial buildings sector.

Response:

a) The total capacity of Enbridge Gas's storage system is 8,046,000 10^3m^3 (314 PJ). This includes 199.4 PJ of cost-based storage for the utility and 117.6 PJ for the non-utility storage. Enbridge Gas can deliver 6.6 PJ from the storage system on design day. The storage system is designed to be able to deliver the design day flow on any day prior to March 1. Theoretically, this would mean that Enbridge Gas could operate for 35 consecutive days at 6.6 PJ.

b) Enbridge Gas is unable to identify storage requirements specifically for the commercial buildings sector as storage capacity is not allocated to specific sectors or customer types.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T10/p. 1

Question(s):

Please specifically set out how energy transition issues have impacted the 2024 revenue requirement and deficiency. What financial impact will energy transition issues have on EGI's rates for the 5-year period beginning in 2024?

Response:

Of the energy transition safe bets issues from Exhibit 1, Tab 10, Schedule 6, Table 1: Summary of Energy Transition Related Rebasing Proposals, page 15 to 18, there are 4 Enbridge Gas initiatives with rebasing proposals; Voluntary RNG Program/Low-Carbon Voluntary Program (LCVP), Natural Gas Vehicle (NGV) Program, Hydrogen Blending Grid Study (HBGS) and the Energy Transition Technology Fund (ETTF). Impacts for the Low Carbon Energy Project (LCEP) Phase 2 were also considered in the calculation, although there was no proposal put forward in Rebasing. Enbridge Gas intends to pursue approval through a leave to construct application.

The impact of these energy transition issues on the 2024 revenue requirement and deficiency is $1.17 million and $0.65 million respectively. The calculation is shown in Table 1.

Table 1
2024 Energy Transition Impacts on Revenue Requirement and Deficiency

($ millions)	2024
Revenue Requirement for capital investments in LCVP, NGV, HBGS, and LCEP	1.32
Recovery of O&M for NGV Program	0.50
Total Revenue Requirement (a)	1.82
Reduction of General service annual volume forecast (approx.. 1,062,274 m^3 for 2024)	-0.10
Revenue forecasted from NGV rental station	1.27
Energy Transition Proposals Impact on Revenue (b)	1.17
Impact to Deficiency (a) minus (b)	**0.65**
ETTF	5.00
Total Impact	**5.65**

The impact to Enbridge Gas's rates of reflecting energy transition issues in the Application is an annual bill increase of $1.49 in 2024 and increases by $0.03 to $1.52 in 2028 for a typical residential customer.

The deficiency impact in 2024 was escalated in future years to estimate bill impacts for 2025 to 2028. The annual bill impact of the ETTF was not escalated. Escalation assumptions include GDP IPI FDD of 2%, productivity of -1.35% and stretch of 0% for an overall PCI of 3.35% per year. No rate rider impacts were assumed for the Voluntary RNG Program, which is proposed to begin in 2025 because the impact, if any, would depend on the uptake of the program.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T10/S2/pp. 15-26

Question(s):

EGI has provided a detailed overview of the Ontario electricity sector. Is the reason why this evidence was produced is to support the statement that, "The IESO's planning activities clearly demonstrate that the gas system, despite longer-term energy transition pathway uncertainty, is needed over the time period covered by this Application."?

Response:

The overview of the Ontario electricity sector provided at Exhibit 1, Tab 10, Schedule 2, pages 15-26 was prepared in order to demonstrate the capabilities of Ontario's electricity sector during the 2024 to 2028 period. This overview was included in evidence because it was part of the data and insights considered in the development of Enbridge Gas's vision of energy transition in Ontario. Please see Exhibit 1, Tab 10, Schedule 5 pages 20-24.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T10/S3/p. 7

Question(s):

“In October 2021, the federal government announced Canada’s commitment to develop a plan to further reduce methane emissions, setting a target of reducing methane emissions by at least 75% below 2012 levels by 2030. In March 2022, the government released a discussion paper and began consulting with the provinces, industry and other stakeholders on how to achieve the increased ambition. Enbridge Inc. submitted a response to the discussion paper.” Please provide a copy of Enbridge Inc.’s response. Please provide the draft regulations when they become available.

Response:

Please see Attachment 1 for Enbridge Inc’s submission in response to the federal discussion paper. Draft regulations have not been published at this time.

Written Submission on Reducing Methane Emissions from Canada's Oil and Gas Sector

Submitted by Enbridge

May 25, 2022

About Enbridge

Enbridge Inc. is a leading North American energy infrastructure company. We safely and reliably deliver the energy people need and want to fuel quality of life. Our core businesses include Liquids Pipelines, which transports approximately 30 percent of the crude oil produced in North America; Gas Transmission and Midstream, which transports approximately 20 percent of the natural gas consumed in the U.S.; Gas Distribution and Storage, which serves approximately 3.9 million retail customers in Ontario and Quebec; and Renewable Power Generation, which owns approximately 1,766 MW (net) in renewable power generation capacity in North America and Europe.

Enbridge believes that climate change requires serious solutions, and that Enbridge can be part of those solutions. Across our business, we've committed to net-zero greenhouse (GHG) emissions by 2050 and to reduce our emissions intensity 35 per cent by 2030. To drive results and accountability, incentive compensation is tied to meeting these commitments.

Introduction

Enbridge is pleased to provide these comments in response to the Discussion Paper on Reducing Methane Emissions from Canada's Oil and Gas Sector prepared by Environment and Climate Change Canada (ECCC) in March 2022.

The majority of Enbridge's methane emissions are from our natural gas transmission, storage, and distribution business units. In 2020, the total volume of methane released from our North American operations was approximately 1.5 million tonnes of carbon dioxide equivalent (tCO2e), which is approximately 2% less than it was in 2019. Enbridge is committed to taking proactive steps to reduce methane emissions as we work to address our own operational emissions to further realize the environmental benefits of natural gas and its role in the energy transition. Where possible, we use multiple approaches at our facilities to reduce methane emissions. This includes the use of a range of methods to detect methane emissions including:

- Optical gas imaging cameras to detect small leaks of fugitive emissions
- Hand-held 'sniffer' gas detectors
- Air patrols on transmission pipelines to enable repair or replacement of faulty equipment

In addition, we are collaborating with our peers through joint industry partnerships on initiatives aimed at innovation and promoting energy efficiency solutions across the natural gas value chain. We also support advocacy that advances smart, cost-efficient regulations that complement voluntary reduction efforts.

ECCC has proposed an alternative approach to regulating methane that would place a greater emphasis on performance-based objectives to achieve at least a 75% reduction in methane emissions from the oil and gas sector from 2012 levels by 2030. Enbridge understands this approach is due in part to methane emissions being historically underreported from the oil and gas sector, and consideration for a way for these regulations to increase monitoring and reporting to better inform decision making. Enbridge appreciates that this approach would provide more flexibility for innovation for specifying the outcome required while leaving compliance solutions to regulated parties. We also understand that a key factor that will influence the design of the regulations is the availability of enhanced monitoring equipment and the ability to set monitoring, measurement and reporting methodologies for some or all of the methane sources to be covered. Enbridge would likely be required to invest capital and operational expenses to upgrade its current monitoring systems and personnel to manage and report data to align with the proposed performance-based approach. As a rate-regulated entity these expenses would likely be passed along to our shipper customers and therefore Enbridge requests that we be invited to the government-led structured sessions to ensure that cost-effective and efficient approaches are taken to the design and implementation of the alternative approach.

Annex I: Discussion Questions

Context

1. What opportunities exist for regulatory cooperation and alignment, domestically and abroad?

   Enbridge recommends that ECCC engage with the United States (U.S.) Environmental Protection Agency (EPA) to identify opportunities for alignment on regulatory approach. A large portion of Enbridge's natural gas transmission and midstream assets are situated in the U.S. and a more consistent approach would create administrative and operational efficiencies.

   Enbridge also recommends that ECCC continue to engage with industry associations, including the Canadian Gas Association (CGA), to collaborate on development of methodologies to enhance the accuracy of measurement and verification and identify opportunities for continuous improvement. Industry has a vast amount of information available to assist ECCC in the development of a performance-based regulation.

2. What lessons from Federal and Provincial regulatory development and Equivalency experiences should be considered?

   The federal government should acknowledge that jurisdictional differences exist between provinces which created the impetus for provincial Equivalency Agreements in the first place. Applying a one-size-fits-all approach to the regulation of methane may not consider logistical and geographic considerations applicable to certain jurisdictions. For example, requiring physical leak-detection and repair of all above-ground natural gas transmission infrastructure may prove challenging due to the remoteness of certain facilities. Therefore, a regional approach which includes the use of aerial monitoring equipment (such as a drone or fixed-wing aircraft) may enable more frequent and accurate measurements versus 'on-the-ground' assessments.

   ECCC should also acknowledge the significant amount of time which was required to establish Equivalency Agreements between the federal and provincial governments, and therefore either build off the existing Agreements or begin negotiations much sooner to promote policy certainty with industry for investing decision making.

3. What best practices or lessons from international jurisdictions should be considered?

   It's important to understand the individual nature of the regulatory frameworks in international jurisdictions and not rush to pick specific items. Many of these international jurisdictions are looking to Canada for inspiration, as we already have some of the most comprehensive and relatively mature approaches to handling methane emissions. Some examples are outlined below:
   - To our knowledge, Canada is the only jurisdiction to have compressor venting limits.
   - Some jurisdictions are focusing on wet seals emissions limits and conversions, whereas the Canadian operators over the past several decades already have shifted to dry gas seals, where

operationally feasible.

- The proposed EU methane regulations exempt transmission and distribution flaring through the definition of routine flaring. Flaring is used in the transmission and distribution sector to reduce emissions from maintenance and operational activities. Restricting flaring in transmission and distribution could inadvertently increase methane emissions.

Regulatory design to achieve at least a 75% reduction by 2030

4. Should Canada retain the approach in its current oil and gas methane regulations, and expand their coverage and increase their stringency?

   Enbridge's natural gas transmission and midstream operations have historically been regulated by a combination of Federal and/or Provincial Equivalency Agreements in British Columbia, Alberta and Saskatchewan, and the federal Methane Regulation in Ontario. The simplest approach, in our estimation, is to continue with the current regulatory framework and then expand the coverage and stringency of the federal, and Provincially Equivalent regulations.

5. Should Canada develop new, performance-based regulations?

   In developing a new, performance-based regulation the Canadian government may want to consider reviewing the proposed framework within the U.S. Methane Emissions Reduction Act of 2021. The proposed Act included an 'opt out' alternative fee calculation method for companies who wished to demonstrate that their emissions intensity was less than the average for the basin in which they operated. In Canada, a similar optional performance-based system could be applied where compliance is measured relative to a methane-based intensity metric tied to throughput (for the transmission segment). A market-based mechanism, similar to the federal Output-Based Pricing System (OBPS), could then be utilized to incentivize enhanced performance based on the lowest-cost mitigation options to address competitiveness and avoid carbon leakage. The key challenge would be avoiding the duplication of regulatory systems which reduce GHG emissions (i.e., overlap between the federal OBPS and a methane performance standard), specifically methane. Enbridge recommends a hybrid approach to allow for flexibility of compliance options (i.e., current approach versus performance-based approach) given the wide range of facilities and operations that may be covered by a new regulation.

   Additionally, as pipelines are operated as systems and not on an individual facility level it makes sense for any performance-based approach to target the pipeline system level.

6. Are there some sources of methane emissions that are not well suited to a performance-based requirement?

   Methane emissions resulting from an Emergency Shutdown (ESD) may not be well suited to a performance-based requirement. ESDs are typically unplanned and due to the high-pressure of natural gas released and the need for a rapid evacuation of internal piping infrastructure the capture of methane is not feasible. One or more ESD's in a given year may negate the performance benefits of mitigative improvements at the facility to no-fault of the owner. Given the lack of options to mitigate methane emissions from an ESD it is not well suited to be covered within a performance-based approach.

   The application of a performance-based regulation would not be appropriate to local distribution systems given that the emissions reported occur across innumerable intermittent, low volume and diffuse sources. There may be limited opportunity to reduce methane emissions beyond company efforts to date and the application of LDAR provisions to distribution systems is not practical and cost prohibitive.

7. What monitoring and reporting requirements should support performance-based requirements?

   Enbridge recommends the deployment of a dedicated methane Conservation Program which would clearly identify the approach and accountabilities related to the monitoring and reduction of methane emissions. The program would establish the requirements for the incorporation of practical mitigative measures to conserve methane within natural gas-related infrastructure. Performance-related reporting would occur via a periodic review of Conservation Program related to regulatory objectives and the GHG emissions verification process providing assurance to data quality.

8. What barriers exist related to methane monitoring? How can they be overcome?

   Infrared (IR) imaging relies on temperature variances to identify and accurately quantify emissions. Detection via IR technologies is effective when ambient temperatures are cooler than the commodity's temperature. During the warm summer months, monitoring/detection is not as effective or efficient. One way of overcoming this barrier is through increased metering (measurement) of the commodity as it moves through the system (i.e., mass balance equation).

   Current methane monitoring methods are labour intensive and expensive to conduct. As well, since natural gas infrastructure can cover large geographical regions, there is often much travel involved. Allowing alternative measurement methodologies such as airborne or satellite methane detection methodologies should be considered as part of the methane regulations.

9. How can real-time measurement technologies be incorporated into the regulations?

   Real time measurement is key to providing data quality assurance but will require the procurement and installation of new monitoring equipment and associated facility upgrades which can be cost prohibitive for many sites. Regulations which establish a minimum standard for the level of detection for methane will set a level playing field across the industry. Real-time measurement technologies are critical to enabling a performance-based regulation based on a metric tied to production (i.e., throughput volumes). This approach will also enable a demonstration of the benefits of Leak Detection and Repair (LDAR) such that compliance penalties can be minimized through quick action to eliminate leaks and subsequent methane emissions.

10. Should the regulations allow a facility to select which regime to be subject to?

    Yes, to enhance compliance flexibility the regulations should enable the facility owner to select which regime to be subject to. This would address competitiveness issues and enable the low-cost approach to methane mitigation to be employed appropriate to the facility. However, in developing the flexible approach the definition of a 'facility' with respect to a linear facility like a pipeline system would need to remain somewhat fixed to minimize administrative burden for reporting, etc.

11. Should it allow this for different methane sources or only on a facility-wide basis?

    As referenced above, some sources of methane emissions are not suitable to be regulated by a performance-based approach and may be more appropriate to be regulated on an absolute basis. Enhanced compliance flexibility will enable the highest volume of methane emissions to be reduced at the lowest cost.

12. How should methane be treated in other oil and gas policies?
    a. Carbon pricing
        i. Methane emissions are not well suited to be regulated through carbon pricing as many sources cannot be measured or quantified accurately enough. However, the carbon price applied in a performance-based approach can be tied to the federal carbon price on a carbon dioxide equivalence basis (i.e., consideration of global warming potential of methane).
    b. The oil and gas sector emissions cap (in development)
        i. The oil and gas sector emissions cap of 42% below 2019 levels by 2030 should integrate the achievement of Canada's target to reduce methane emissions by 75% from 2012 levels by 2030. Methane regulations should be complimentary to the achievement of the sector emissions cap without unnecessary duplication. The absolute, or performance-based, methane regulation should constitute the 'workhorse' of reducing methane emissions to avoid regulatory duplication and contributing to competitiveness and carbon leakage issues.

Net zero by 2050

13. From the perspective of achieving net-zero GHG emissions by 2050, should any reductions for methane emissions be considered "dead ends" and avoided in the regulations?

    It is our view that local distribution systems should not be regulated. Overlapping LDAR surveys would generate more confusion/risks without substantial difference in emissions. Leak detection is the easy part; repairs are complicated and must be planned carefully to ensure safety of the workers and communities as well as an uninterrupted supply of energy to the consumers. There are diminishing returns from increasing LDAR frequency. There will inevitably be some amount of leakage that will occur, as safety features are included in facilities to avoid overpressure situations resulting in occasional but necessary methane emissions . We can endeavour to reduce as much as possible, but these emissions will likely need to be offset in a net-zero future.

Supportive measures

14. What activities should the science and research community prioritize to support methane reduction?

    The science and research community should prioritize the use of remote sensing technologies to reduce the cost of and improve the quality of measuring methane emissions. The technology would be particularly useful in measuring methane emissions, if any, from remote valve stations (in lieu of a hands-on approach) or other infrastructure.

15. What measures would accelerate deployment of methane reduction technology?

    Economic incentives provided by the generation (and monetization) of carbon offset credits achieved through reductions in methane which are beyond compliance could incentivize investment in innovative methane reduction technologies. For example, the generation of Technology Innovation and Emissions Reduction

(TIER) credits in Alberta through the replacement of pneumatic valves has contributed to a large volume of avoided methane emission reductions which has enabled the practice to 'come to scale' and become more economic.

Conceptually, these carbon offset credits could be used as a compliance pathway in a performance-based regulation for methane. Similarly, revenue generated by a performance-based methane regulation could be recycled into grants for research, development, and investment in emerging methane reduction technology to accelerate deployment more broadly.

16. What limits the deployment of methane reduction technology?

    Deployment of methane reduction technology is limited primarily by the absence of more stringent regulatory requirements to reduce and/or eliminate methane emissions. In addition, the cost of capturing methane from venting and flaring remains somewhat cost-prohibitive and large-scale deployment will require improved economics. More cost-effective real-time measurement of methane emissions will enable enhanced LDAR and subsequent reduction/avoidance of fugitive emission sources.

17. How should a centre for excellence on methane detection and elimination be leveraged to support strengthened methane regulations?

    A Centre for Excellence of methane detection and elimination could be financially supported through the revenue generated by a performance-based methane regulation. The Centre could focus on improving real-time measurement devices and the advancement of technologies to capture methane emissions at various natural-gas related facilities, including sharing best practices across industry.

Conclusion

Thank you for this opportunity to provide input on Reducing Methane Emissions from Canada's Oil and Gas Sector. If you have any questions, please do not hesitate to contact amanda.affonso@enbridge.com

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 10/S4/p. 4

Question(s):

"Energy transition adjustments were considered for the general service average use forecast, as well as for the general service number of customers forecast." Please provide the following:

a) The average use forecast for the residential rate classes for the period 2013-2024;

b) The actual average use for the residential rate classes for the period 2013-2023;

c) The actual average use for the residential rate classes on a weather normalized basis for the period 2013-2023;

d) The customer number forecast for the residential rate classes for the period 2013-2024;

e) The actual customer numbers for the residential rate classes for the years 2013-2022

Response:

a) Please see Exhibit 3, Tab 2, Schedule 5, Attachment 7, page 2 for the normalized residential average use for the period 2013 to 2024.

b) Please see Attachment 1 for the actual unnormalized residential average use for the period 2013 to 2024.

c) Please see part a).

d-e) Please see Exhibit 3, Tab 2, Schedule 6, Attachment 2 for the residential average number of customers for the period 2013 to 2024.

Table 1-Enbridge Gas Un-Normalized Residential Average Use

Line No.	Particulars (m^3)	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Residential	2,516	2,682	2,448	2,264	2,338	2,464	2,531	2,297	2,193	2,295	2,254	2,270

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 1/T10/S4/p. 8

Question(s):

"As a result of the energy transition adjustment to the customer forecast, the 2024 Test Year general service annual volume forecast is approximately 2,899,408 cubic meters per year lower that would otherwise be the case." What is the impact of this reduction on the revenue deficiency?

Response:

The energy transition assumptions impact on the 2024 Test Year general service volume that was provided at Exhibit 1, Tab 10, Schedule 4, page 8 is incorrect. The volumetric impact of 321 fewer customer additions is 1,062,274 m^3. Please see response at Exhibit I.1.10-STAFF-31, Table 7 for a detailed calculation. Regarding the impact of this on the revenue deficiency please see response at Exhibit I.1.10-CCC-28.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, p. 7 of 20, Figure 1

Question(s):

At Figure 1, EGI models its forecast on customer additions through the 2023-2032 period before and after accounting for energy transition assumptions.

a) The Canadian government has recently indicated a desire to significantly increase immigration to Canada with a target of 500,000 by 2025.[1] According to the Government of Ontario, Ontario often receives between 40% and 50% of all immigrants that come to Canada.[2] Does the announcement of an increase in immigration targets impact EGI's forecasting of customer additions through the plan period? Please explain fully.

Response:

a) Enbridge Gas relies on its Consensus Housing Starts forecast to develop its new construction customer additions forecast. Please see response at Exhibit I.3.2-SEC-154 for the sources of the Consensus Housing Starts forecast. The Canadian Government's immigration targets are not a direct input into Enbridge Gas' customer additions forecasting process. The Company cannot comment on the specific methodologies underpinning the individual forecasts that form the Consensus Housing Starts forecast, but to the extent that immigration targets and other assumptions have been incorporated through the Consensus Housing Starts forecast, the Company's customer additions forecast will reflect those assumptions.

[1] See the following Bloomberg article for additional information https://www.bloomberg.com/news/articles/2023-01-03/immigration-to-canada-hits-record-as-trudeau-seeks-more-workers?leadSource=uverify%20wall
[2] See the following Demographic Quarterly from the Government of Ontario: https://www.ontario.ca/page/ontario-demographic-quarterly-highlights-fourth-quarter

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 6, p. 16 of 40

Question(s):

At page 16, EGI explains its proposal with respect to the “Low Carbon Voluntary Program” (LCVP). EGI stated that the program would have EGI procure between 1-4% of its planned gas supply commodity purchases as low-carbon energy. This program would then be offered to large volume sales service customers to purchase to be made part of their gas supply. EGI then states any costs not recovered through the program would be included in the general cost of gas supply commodity purchases.

a) Please confirm that to the extent the costs are not absorbed by the LCVP, the costs will be apportioned to ratepayers on a non-voluntary basis.

b) Has EGI forecasted the voluntary uptake of low carbon energy amongst large volume sales service customers, and how much of the cost of the procurement of low-carbon energy would therefore be voluntarily borne by those customers?

c) If the answer to (b) is yes, please provide EGI’s forecast of the volume and costs that it forecasts will be absorbed by the LCVP program, and the costs that it expects will be borne by non-participants.

d) As CME understands it, the uptake for the Voluntary Renewable Natural Gas program was lower than anticipated. However, there are still a number of participants currently. Has EGI considered whether or not it could offer to apportion any leftover low-carbon energy to voluntary participants who are not large volume sales service customers before apportioning those costs in the general cost of gas supply commodity purchases?

e) If the answer to (d) is yes, please explain why EGI is not proposing to apportion costs amongst additional voluntary participants first.

f) If the answer to (d) is no, please provide EGI’s position on that type of program structure.

Response:

a-f) This issue will be addressed in Phase 2 of the proceeding in accordance with the OEB's Decision on Issues List dated January 27, 2023.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 2, Page 2

Preamble:

“On a peak basis, the natural gas system provides three to five times as much energy as the electricity system. For example, the most recent winter peak (highest hourly flow measured during the winter) occurred at 9 am on January 22, 2022 and was 8,507 103m3/hr or approximately 92 GW. In comparison, the amount of electricity generated in Ontario at the same time was approximately 21 GW, and of this around 20 GW was to serve demand within the province. The amount of electricity generated was close to 70% of the 30.2 GW effective winter capacity.”

Question(s):

a) Please provide the temperature at 9 am on January 22, 2022 (i) in Toronto, and (ii) as an average for Enbridge customers that is population-weighted (i.e. reflecting the fact that most customers are in Southern Ontario). An approximation may be used for the population-weighting. Please provide the calculations.

b) Please provide the temperature, date, time, and GW Ontario electricity demand at the coincident winter peak hour on the electricity system in Ontario in the winter of 2021-2022.

c) Please provide the approximate co-efficient of performance (“COP”) of 3-ton centrally ducted Mitsubishi-Zuba system and Moovair Central system at the temperatures in the answers to (a) and (b). Please indicate the tool or method used to estimate the COP and indicate if the tools found at neep.org would generate a different result, and if yes, please explain. If necessary, please contact the manufacturers to access the information.

d) What temperature does the IESO use to model electricity demand from heating at the time of the coincident electricity system peak for the purposes of determining the electricity resource adequacy.

Response:

a) Enbridge Gas notes that there is an error in the evidence at Exhibit 1, Tab 10, Schedule 2, page 2. The date on which the most recent winter peak (highest hourly flow measured during the winter) occurred was January 20, 2022, not January 22, 2022, as shown.

The temperature in Toronto at 9am on January 20, 2022, was -16.8°C[1] as reported at the weather station at the Toronto International Airport. Please see Exhibit 4, Tab, 2, Schedule 3, page, 18, for the design temperatures used by the Company for Ontario. Due to the variability in temperature across the province a single temperature for Ontario is not possible to provide nor would a population weighted average be appropriate.

b) The highest demand on the electricity system for the winter of 2021-2022 (assumed to be December 1, 2021, to March 31, 2022) occurred on January 20, 2022, for the hour ending at 18:00 (6:00 pm). The demand was 21,349 MW.[2,3] The temperature for Ontario at this time cannot be provided as there is no single temperature for all of Ontario, however the temperature in Toronto at this time was -14.0°C as reported at the weather station at the Toronto International Airport.[4]

c) Please refer to the manufacturers' websites for the approximate COPs for the referenced product lines. Due to the varied combinations of units for a given heating system, it would take considerable time to estimate the approximate COP for the product lines noted, with uncertainty in the estimates. Enbridge Gas is declining to

[1] Hourly Data Report for January 20, 2022, Environment Canada, last modified 2023-01-31, Source: https://climate.weather.gc.ca/climate_data/hourly_data_e.html?hlyRange=2013-06-11%7C2023-02-14&dlyRange=2013-06-13%7C2023-02-13&mlyRange=%7C&StationID=51459&Prov=ON&urlExtension=_e.html&searchType=stnName&optLimit=yearRange&StartYear=1840&EndYear=2023&selRowPerPage=25&Line=51&searchMethod=contains&txtStationName=Toronto&timeframe=1&time=LST&time=LST&Year=2022&Month=1&Day=20#
[2] Hourly Demand Report, 2021, http://reports.ieso.ca/public/Demand/PUB_Demand_2021.csv
[3] Hourly Demand Report, 2022, http://reports.ieso.ca/public/Demand/PUB_Demand_2022.csv
[4] Hourly Data Report for January 20, 2022, Environment Canada, last modified 2023-01-31, Source: https://climate.weather.gc.ca/climate_data/hourly_data_e.html?hlyRange=2013-06-11%7C2023-02-14&dlyRange=2013-06-13%7C2023-02-13&mlyRange=%7C&StationID=51459&Prov=ON&urlExtension=_e.html&searchType=stnName&optLimit=yearRange&StartYear=1840&EndYear=2023&selRowPerPage=25&Line=51&searchMethod=contains&txtStationName=Toronto&timeframe=1&time=LST&time=LST&Year=2022&Month=1&Day=20#

contact the manufacturers or complete the significant work required to complete this request.

d) Enbridge Gas is not aware of the temperature the IESO uses to model electricity demand from heating.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 2, Page 13

Preamble:

"Ontario's natural gas system provides reliable, resilient, and secure energy in a cost-effective manner. According to the OEB's 2020 Yearbook of Natural Gas Distributors, Ontario's natural gas distributors received $5.1 billion in total revenue for services related to natural gas supply, transport and distribution in 2019. During the same period, the 2020 Yearbook of Electricity Distributors lists power and distribution revenues of $21.7B for Ontario's electricity distributors. Even if the differential between these revenues is adjusted for energy payments to other parties (natural gas marketers who provide natural gas supply to large users, for example), the conclusion that natural gas is very cost effective is inescapable, given that natural gas energy accounted for 30% of total energy demand of Ontario while electricity accounted for 16% of total energy demand in 2019, as shown in Figure 1."

Question(s):

a) The above passage states: "[e]ven if the differential between these revenues is adjusted for energy payments to other parties…" Please calculate the adjustment and provide the adjusted differential. Please include the calculations.

b) Please provide the ratio of T&D costs to commodity costs in Ontario for (i) gas and (ii) electricity.

c) Please provide an estimate of the total costs incurred by Ontario customers in 2020 including commodity (incl. upstream transportation), transmission, distribution, and carbon costs. For volumes of gas not purchased from Enbridge, please either use Enbridge's best estimate of the price paid for the gas or provide the average gas cost for the gas that Enbridge sells to its own customers.

d) Please provide an estimate of the total electricity costs incurred by Ontario customers in 2020 including commodity, transmission, distribution, and carbon costs.

e) Please provide the figures calculated in (c), (d), for the latest year possible (i.e. 2022 if possible).

f) If the figures cannot be calculated for 2022, please recalculate the figure in (c) with the commodity costs increased by the percentage difference in the average commodity costs for 2020 versus 2022.

g) Please recalculate the figure in (c) as if the 2030 carbon prices applied.

<u>Response:</u>

a) Please see Exhibit 1, Tab 10, Schedule 2, page 14, footnote 40.

b)
   i. Using the 2020 estimate gas costs provided in Table 1 for part c), the ratio of T&D costs to commodity costs for gas is 1.18.

   ii. Enbridge Gas does not have the information requested and declines to estimate it. There are more than 50 electricity distributors and transmitters in Ontario; therefore, it would take a significant amount of time and effort to review their respective rate cases for the T&D costs.

c) Please see Table 1 for an estimate of gas costs incurred by Ontario customers in 2020.

Table 1: Total Estimated Gas Costs Incurred by Ontario Customers in 2020

Line No.	Particulars ($millions)	2020
1	Annual estimated commodity costs (1)	2,488.7
2	Annual transportation costs (2)	428.0
3	Annual distribution costs	2,314.8
4	Annual carbon costs (3)	809.1
5	Annual other gas related costs (4))	176.5
6	Total estimated gas costs incurred by Ontario customers	6,217.0

Notes

(1) Estimated commodity cost for customers who do not purchase gas from Enbridge is calculated using the weighted average commodity prices that Enbridge system sales customers paid

(2) Estimated transportation cost for customers who do not purchase gas from Enbridge is not available. Please see response at Exhibit I.1.10-ED-5, part c.

(3) Carbon costs billed to non-exempt Enbridge Gas customers are included but carbon costs associated with exempt entities registered in the Federal Output-Based Pricing System (OBPS) are not included. An OBPS entity’s carbon compliance costs are strictly between them and the federal government and therefore not publicly available.

(4) Other costs include load balancing & storage costs

d) Enbridge Gas notes that there is an error in the evidence at Exhibit 1, Tab 10, Schedule 2, page 13. The power and distribution revenues noted for 2019 from the 2020 OEB yearbook for Electricity Distributors is $17.8B not $21.7B as shown.

Please see Table 2 for an estimate of the total electricity costs incurred by Ontarians in 2020.

Table 2: Total Estimated Electricity Costs Incurred by Ontario Customers in 2020

Line No.	Particulars ($millions)	2020
1	Annual estimated distribution revenue (1)	3,898
2	Annual estimated cost of power (1)	16,090
3	Annual estimated transmission revenue (2)	1,685
4	Annual carbon costs (3)	N/A
5	Annual estimated government subsidies (4)	4,800
6	Total estimated electricity costs incurred by Ontario customers	26,473

Notes

(1)	2020 OEB yearbook for Electricity Distributors
(2)	EB-2019-0296 Decision and Order
(3)	Power producers are typically registered in the Federal Output-Based Pricing System (OBPS) and are therefore identified as exempt entities in Enbridge Gas's systems. Since an OBPS entity's carbon compliance costs are strictly between them and the federal government, and not publicly available, Enbridge Gas is unable to provide an estimate of the carbon costs.
(4)	https://www.fao-on.org/en/Blog/publications/energy-and-electricity-2022

e) Please see Table 3 for an estimate of gas costs incurred by Ontario customers in 2022. Please see Table 4 for an estimate of the electricity cost incurred by Ontario customers in 2021. An estimate for 2022 is not able to be provided as the OEB yearbook for Electricity Distributors hasn't been released.

Table 3: Total Estimated Gas Costs Incurred by Ontario customers in 2022

Line No.	Particulars ($millions)	2022
1	Annual estimated commodity costs (1)	5,972.7
2	Annual transportation costs (2)	426.6
3	Annual distribution costs	2,572.3
4	Annual carbon costs (3)	1,486.0
5	Annual other gas related costs (4)	193.2
6	Total estimated gas costs incurred by Ontario customers	10,650.7

Notes

(1) Estimated commodity cost for customers who do not purchase gas from Enbridge is calculated using the weighted average commodity prices that Enbridge system sales customers paid

(2) Estimated transportation cost for customers who do not purchase gas from Enbridge is not available. Please see response at Exhibit I.1.10-ED-5, part c.

(3) Carbon costs billed to non-exempt Enbridge Gas customers are included but carbon costs associated with exempt entities registered in the Ontario Emissions Performance Standards (EPS) are not included. An EPS entity's carbon compliance costs are strictly between them and the Ontario government and therefore not publicly available. The 2022 carbon cost is subject to change pending the results of the third-party verification of Enbridge Gas's 2022 Emissions Performance Standards compliance obligation, which is expected by Q2 2023.

(4) Other costs include load balancing & storage costs

Table 4: Total Estimated Electricity Costs Incurred by Ontario Customers in 2021

Line No.	Particulars ($millions)	2021
1	Annual estimated distribution revenue (1)	4,092
2	Annual estimated cost of power (1)	13,955
3	Annual estimated transmission revenue (2)	1,792
4	Annual carbon costs (3)	N/A
5	Annual estimated government subsidies (4)	5,485
6	Total estimated electricity costs incurred by Ontario customers	25,324

Notes
(1) 2021 OEB yearbook for Electricity Distributors
(2) EB-2020-0251 Decision and Order
(3) Power producers are typically registered in the Federal Output-Based Pricing System (OBPS) and are therefore identified as exempt entities in Enbridge Gas's systems. Since an OBPS entity's carbon compliance costs are strictly between them and the federal government, and not publicly available, Enbridge Gas is unable to provide an estimate of the carbon costs.
(4) https://www.fao-on.org/en/Blog/publications/energy-and-electricity-2022

f) Please see part e) for the estimate of gas costs incurred by Ontario customers in 2022.

g) Assuming the carbon price for 2030 is \$170/tCO$_2$e or 32.4 cents/m^3, the 2020 carbon cost at 2030 rates would be \$5,373.84 million[1]. This calculation assumes Enbridge Gas's throughput is 100% natural gas. By 2030, Enbridge Gas anticipates that low carbon fuels such as RNG and hydrogen will make up a portion of the Company's total gas throughput, thus lowering the total carbon costs incurred by customers since RNG and hydrogen are not subject to the carbon charge. The total 2020 estimated gas costs incurred by Enbridge customers as provided in Table 1 using 2030 carbon rates would be \$10,781.3 million. Enbridge Gas notes that this is a hypothetical scenario, and this estimated total gas cost is not based on the Company's forecasts.

[1] This calculation takes the 2020 calendar year gas volumes subject to the carbon charge and multiplies by the 2030 carbon price. It does not consider the 2029 carbon price which would be in place from January to March of 2030. This estimate only includes carbon costs billed to non-exempt Enbridge Gas customers.

ENBRIDGE GAS INC.

Answer to Interrogatory from Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 2, Page 13

Preamble:

"According to the OEB's 2020 Yearbook of Natural Gas Distributors, Ontario's natural gas distributors received $5.1 billion in total revenue for services related to natural gas supply, transport and distribution in 2019. During the same period, the 2020 Yearbook of Electricity Distributors lists power and distribution revenues of $21.7B for Ontario's electricity distributors"

Question(s):

a) Approximately percent of gas consumed in Ontario is imported from out-of-province?

b) Approximately percent of electricity consumed in Ontario is imported from out-of-province?

c) Approximately how much did Ontario's gas consumers pay in 2020 for gas transmission costs (i.e. the cost to transport the gas to Ontario)? Please provide an estimate on a best-efforts basis and with any necessary caveats. If you do not have the upstream transmission costs for direct purchase customer volumes, please indicate that volume (m3), the average cost for upstream transmission for volumes purchased by Enbridge for its customers ($/m3), and the cost for direct purchase customers extrapolated therefrom.

Response:

a) According to the Canada Energy Regulator[1], approximately 99.7% of natural gas consumed in Ontario in 2020 was imported from out-of-province.

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[1] Canada Energy Regulator. (2022, July 28). Energy Production. Provincial and Territorial Energy Profiles – Ontario. https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html Ontario average gas consumption = 2,700 mmcf/d; Ontario average gas production = 6.9 mmcf/d (99.7% of average consumption).

b) According to the IESO, in 2021 approximately 6.5% of electricity consumed in Ontario was imported.[2,3,4]

c) Enbridge Gas customers in Ontario paid approximately $375 million of transmission costs in 2020 to transport gas to Ontario. These costs include transmission costs paid by Enbridge Gas on behalf of all systems sales customers in all rate zones, bundled direct purchase customers for Union North rate zone and the western bundled T-service customers for EGD rate zones. Enbridge Gas does not believe it is appropriate to estimate the transmission costs for the remaining direct purchase customers by using the average cost paid by the above-mentioned customers because it is unlikely that this average cost would be representative of the cost of upstream transportation contracts held by individual direct purchase customers. These customers are obligated to deliver supply to various points on Enbridge Gas's system, but they are not obligated to acquire upstream transportation to these delivery locations. It is likely that many of these obligated deliveries are met by purchasing gas directly at the obligated receipt point from gas marketers and producers, and the price paid by the direct purchase customer would be reflective of any costs to move gas to the delivery location. Enbridge Gas does not have insight into the gas purchase transactions or supply arrangements of these customers.

[2] 2021 imports of electricity were 8.7 TWh. Source: IESO, Supply Overview, Imports and Exports, https://www.ieso.ca/en/Power-Data/Supply-Overview/Imports-and-Exports
[3] 2021 annual Ontario electricity demand was 133.8 TWh. Source: IESO, Demand Overview, Historical Demand, https://www.ieso.ca/en/Power-Data/Demand-Overview/Historical-Demand
[4] 8.7 TWh/133.8TWh = 0.065 OR ~ 6.5%

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 2, Page 14

Preamble:

"Enbridge Gas's residential customers will pay approximately $45/month in distribution revenues based on Enbridge Gas's proposal, which reflects the value of resiliency, reliability and security provided by Enbridge Gas's rate base."

Question(s):

a) Please provide the approximate monthly average residential distribution costs for (i) Ontario electricity customers on average and (ii) customers of Toronto Hydro.

Response:

a) Enbridge Gas does not have the information requested. There are more than 50 electricity distributors in Ontario, therefore it would take a significant amount of time and effort to review their respective rate cases for the distribution revenues associated with residential LDC customers. The $45/month in distribution revenues represents the value proposition to consumers of providing access to the safe and reliable system Enbridge Gas operates, which also carries the additional benefit of providing a distinct and separate energy delivery service for consumers along with the electricity system.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 2, Page 14

Question(s):

a) Please confirm that gas heating usually also requires electricity (e.g. for furnace electronics and for the blower).

b) Approximately what percent of Enbridge residential customers have backup power?

Response:

a) Confirmed.

b) In the 2020 Single Family Residential Natural Gas End Use survey, 12% of single-family residential customers indicated they had a source of back-up power. Please see Exhibit I.1.10-GEC-7, Attachment 3, page 22.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 2, Page 14
Dunsky, *Ontario's Distributed Energy Resources (DER) Potential Study*, Prepared for the IESO, September 28, 2022 (link)

Preamble:

"48. The IESO forecasts incremental capacity needs of 1,796 MW with the continued availability of existing resources in 2025; by 2032 these incremental needs are expected to grow to 3,443 MW."

Question(s):

a) Please confirm that the above-reference DER potential study found that the achievable potential for distributed energy resource by 2032 is between 1.3 and 4.3 GW.[1] Please indicate if Enbridge disagrees with this figure, and if yes, please provide Enbridge's estimate.[2]

b) Please confirm that the above-reference DER potential study found as follows:

> The economic potential results indicate there is ample cost-effective DER capacity to meet or exceed all incremental system needs under all scenarios.

[1] Dunsky, *Ontario's Distributed Energy Resources (DER) Potential Study*, Prepared for the IESO, September 28, 2022 (link), p. ES-2.
[2] Ibid.

Table E-1: System Incremental Seasonal Capacity Needs vs Economic and Achievable Potential Results

Seasonal Capacity	Potential	BAU	BAU+	Accelerated
Summer 2032	**Incremental System Needs**	**2.6 GW**	**5.6 GW**	**6.9 GW**
	Economic Potential	4.1 GW *(15% of peak demand)*	8.2 GW *(27% of peak demand)*	18.9 GW *(61% of peak demand)*
	Achievable Potential	1.3 GW *(5% of peak demand)*	2.2 GW *(7% of peak demand)*	4.3 GW *(14% of peak demand)*
Winter 2032	**Incremental System Needs**	**0.9 GW**	**6.4 GW**	**13.3 GW**
	Economic Potential	2.8 GW *(11% of peak demand)*	6.8 GW *(22% of peak demand)*	15.0 GW *(40% of peak demand)*
	Achievable Potential	1.0 GW *(4% of peak demand)*	1.8 GW *(6% of peak demand)*	3.6 GW *(9% of peak demand)*

The gap between achievable and economic potentials relates to a range of factors, including DER adoption and diffusion, market barriers, DR program participation limits and the limited financial attractiveness of some DERs to specific customers. This gap can be narrowed through actions such as improving DER compensation for services like capacity and T&D benefits, securing DERs more directly through programs or procurements, and by enhancing opportunities for DERs to participate in wholesale markets.

Please indicate if Enbridge disagrees with these conclusions, and if yes, please provide Enbridge's alternative conclusions.

Response:

a-b) Based on the quoted text in the preamble, Enbridge Gas takes the referenced evidence to be on page 19 of Schedule 2 and not page 14 as indicated.

As provided at Exhibit 1, Tab 10, Schedule 2, pages 21 to 22, the IESO has planned actions to address the referenced capacity gaps. Enbridge Gas cannot comment on the accuracy of the findings of the DER Potential Study or how the IESO will use them to meet the capacity gaps identified in their 2021 APO; however, as provided at Exhibit 1, Tab 10, Schedule 2, page 24, footnote 80, Enbridge Gas acknowledges that the DER Potential Study suggests that DERs could meet capacity deficits identified out to 2032.

Further to the above, Enbridge Gas recognizes the potential DERs could have in the future as Ontario moves through the energy transition. DERs align with Enbridge Gas's view of a diversified pathway to a net-zero economy in Ontario. The potential of DERs is demonstrated in the Pathways to Net-Zero for Ontario Report. The sensitivity analysis on the role of DERs provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, pages 50 to 51, assumed that 50% of all new solar capacity was sited behind the meter and that the costs of renewables are significantly reduced. The result is that approximately 2 GW of solar capacity is sited behind the meter as DERs by 2050. Please see response at Exhibit I.1.10-ED-46 for the installed solar capacity of the base diversified scenario in 2050.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 2, Page 24

Preamble:

"the proposed federal Clean Electricity Regulations, which would require the electricity sector to have net-zero emissions by 2035, create uncertainties regarding the future of gas-fired generation."

Question(s):

a) Please file on the record the latest information about the Clean Electricity Regulations available at the time that interrogatory responses are provided.

b) Based on the latest information available to Enbridge, what is Enbridge's best estimate of the impact of the clean electricity regulations for gas demand (annual and peak) in Ontario by 2035?

c) Please provide a table showing the annual demand and design day demand attributable to gas powered power generation in Ontario from 2020 (historical) to 2035 (forecast).

d) Please provide a table showing the annual demand and design day demand attributable to gas powered power generation in Ontario from 2020 (historical) to 2035 (forecast) focusing only on the demand served by the Dawn-Parkway system.

e) Has Enbridge made comments to the federal government regarding the content of the Clean Electricity Regulations? If yes, please provide a list of those comments, including both those provided publicly and privately.

f) Please file a copy of all comments made by Enbridge to the federal government regarding the content of the Clean Electricity Regulations.

Response:

a) Please see the Proposed Frame for the Clean Electricity Regulations[1].

b) Please see response at Exhibit I.1.10-STAFF-30 part d).

c-d) The design day demand and annual demand attributable to gas powered power generation in Ontario and served by the Dawn Parkway System is provided at Table 1 and Table 2, respectively.

Table 1
Design Day Demand (10^3m^3/day)

Line No.	Year	Ontario Gas Powered Generation (a)	Ontario Gas Powered Generation served by Dawn Parkway (b)
1	2020	28,560	20,984
2	2021	28,560	20,984
3	2022	28,560	20,984
4	2023	28,560	20,984
5	2024	30,027	20,984
6	2025	30,027	20,984
7	2026	30,027	20,984
8	2027	30,027	20,984
9	2028	30,027	20,984
10	2029	30,027	20,984
11	2030	30,027	20,984
12	2031	30,027	20,984
13	2032	30,027	20,984
14	2033	30,027	20,984
15	2034	30,027	20,984
16	2035	30,027	20,984

[1] Government of Canada. (2022, Jul 26). Proposed Frame for the Clean Electricity Regulations. https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/publications/proposed-frame-clean-electricity-regulations.html

Table 2

Annual Demand (10^3m^3)

Line No.	Year (1)	Ontario Gas Powered Generation	Ontario Gas Powered Generation served by Dawn Parkway
		(a)	(b)
1	2020	1,441,266	1,055,196
2	2021	1,854,931	1,344,584
3	2022	2,689,360	1,925,229
4	2023	2,126,871	1,632,353
5	2024	2,256,083	1,685,353
6	2025	2,426,083	1,685,353
7	2026	2,426,083	1,685,353
8	2027	2,426,083	1,685,353
9	2028	2,426,083	1,685,353

Notes:

(1) Enbridge Gas has provided volume forecast data covering the 2023 Bridge Year, 2024 Test Year and subsequent IRM period requested in this application.

e-f) Enbridge Gas submitted the following comments during the federal government's consultation periods seeking input on the Clean Electricity Regulations:

i. Written Submission on Clean Electricity Standard Discussion Paper, provided at Attachment 1; and

ii. Written Submission on Clean Electricity Regulations Framework, provided at Attachment 2.

Written Submission on Clean Electricity Standard Discussion Paper

Submitted by Enbridge

April 14, 2022

About Enbridge

Enbridge Inc. is a leading North American energy infrastructure company. Our core businesses include Liquids Pipelines, which transports about 30% of the crude oil produced in North America; Gas Transmission and Midstream, which transports about 20% of the natural gas consumed in the U.S.; Gas Distribution and Storage, which serves approximately 3.9 million retail customers in Ontario and Quebec; and Renewable Power Generation, which has 2,172 megawatts (net) in operating renewable power generation capacity in North America and Europe. We appreciate the opportunity to provide comments on the Government of Canada's (GoC) "A clean electricity standard in support of a net-zero electricity sector" discussion paper.

Introduction

Enbridge supports the GoC's goals of having a net-zero economy by 2050. We have adopted strong greenhouse gas (GHG) emission reduction targets at our company as part of our larger Environment, Social and Governance plan, including elimination of GHG emissions from our business on a net basis (net-zero) by 2050 with an interim emissions intensity reduction target of 35% by 2030. We further support GoC establishing clear regulations and market signals now, given the long timelines for infrastructure development in the electricity sector and in the provincial regulatory frameworks required to support a net-zero grid. This proactive approach will help ensure that the transition is cost-efficient for ratepayers across the country by providing the certainty needed to inform business decision making.

There are three key principles to consider in ensuring Canada's grid continues to meet the needs of its ratepayers in a low-carbon world:

- **Reliability:** the grid must be able to deliver power to end-users when needed. This is best achieved via diverse resource types, attributes, and geographical locations complementing each other in the daily operation of Canada's regional grids.
- **Net-zero emissions:** the grid must achieve net-zero emissions but this does not have to mean producing no emissions at all. Negative emission technologies, paired with low- and non-emitting technologies, can achieve the desired environmental benefits.
- **Affordability:** Whether major power consumers spending hundreds of millions of dollars on electricity each year, or a family on a tight budget, even "small" price increases of 5%-10% can have significant impacts. The transition to net-zero should happen in a manner that meets the target but strategically approaches change to minimize avoidable costs, including long-term costs.

Enbridge submits that regulations and enabling standards developed under this consultation should continue to include consideration of these principles and provide provinces and territories the flexibility they need to also tailor their individual pathways to net-zero. For example, it may be more economical and efficient to remove carbon from other fuels and emission sources before addressing the last remaining electricity-based emissions on the pathway to net-zero in 2050; regions should have the flexibility to encourage the lowest-cost carbon abatement wherever it occurs to ensure the transition to net-zero is in keeping with the principles above.

Enbridge agrees with the GoC that the best approach for Canada to reach net-zero, with consideration for the above principles, is to acknowledge regional differences and to take an "all solutions" approach. Renewable energy and power storage will play a major role, but to meet net-zero these resources must be supported by natural gas, including when paired with carbon capture, utilization and storage (CCUS), low-carbon hydrogen, Renewable Natural Gas (RNG), and waste heat resources, among others. This approach will also be appropriate for the economy-wide targets, as not all energy consumption can be electrified, for example, natural gas-fired home heating and industrial heat applications will continue to require gas for the foreseeable future, including unabated gas, during the transition period.

A Clean Electricity Standard (CES) that incentivizes the transition to low-emitting and non-emitting resources on our provincial and territorial grids, but that does not mandate the complete elimination of fossil fuels, is the best way to ensure Canada can meet its climate commitments while maintaining the reliability and affordability of our grid.

We support the GoC's proposal to develop new interties between provinces, e.g., the Atlantic Loop project. We further support the GoC's announced spending on smart renewable energy and grid technologies, and remote and Indigenous clean energy projects. Finally, we support the Investment Tax Credits (ITC) included in the 2022 budget announcement for CCUS, and the GoC's plan to design ITCs for net-zero technologies, battery power storage and clean hydrogen, and we look forward to participating in consultations on those programs. These tax credits and other programs will provide critical financial support for emerging technologies that will play a major role in Canada's net-zero grid future. We submit similar federal support for transmission planning and development could help support the anticipated increase in renewable energy and other emissions-free power.

Enbridge looks forward to the GoC sharing proposed technical details of the CES. We have responded to the GoC questions below where we have operational and strategic experience, and we look forward to continuing participation in CES consultations in the coming months.

Response to Questions

General

1. **Should interim standards be included in the period before 2035?**

   Interim standards are unnecessary where there is a properly designed, tightening carbon pricing regime in the Output Based Pricing System (OBPS) treatment of electricity and/or the provincial equivalent programs. The discussion paper notes that the treatment of electricity under the OBPS would be addressed as part of this consultation, and Enbridge agrees that is an effective pathway to support the grid transition as we move toward the 2035 target.

   We appreciate the GoC's suggestion that robust use of offsets could be an important compliance mechanism during this transition period. Including electricity in the OBPS (and provincial programs), accompanied by clear offset protocols to enable compliance during the transition will provide the predictable market signals needed for electricity generators and major power consumers to make informed business decisions. It will also provide provincial and territorial governments and market administrators the solid regulatory underpinnings to develop needed transition plans, regulatory frameworks, and market design updates.

   We submit that the GoC's design of the offset system should be aligned with CES-based systems in existing Canadian and U.S.-based markets to the extent practical to maximize marketability and fungibility of Canadian-generated offsets, to further encourage development. Additionally, offsets should be capped at increasingly stringent rates through the transition period to ensure real emissions reductions are realized in the lead up to 2035.

2. How should the CES regulation be designed to minimize stranded capital assets and associated rate impacts?

The GoC's establishment of the CES well in advance of the 2035 target date already goes a long way to minimize future stranded assets. Insofar as the CES establishes clear, long-term signals new investments in emissions-heavy electricity resources will be minimized or avoided, and investment will focus on non-emitting and low-emitting resources.

The accommodation of hydrogen and RNG blending, CCUS, and other low-emitting technologies and retrofits, paired with offsets, will further minimize stranded assets and associated rate impacts. The inclusion of these low-emitting solutions will help natural gas-fired resources stay online during and even beyond 2035 where they can reduce or offset their emissions within the CES standards. Maximizing use of these existing assets will help ensure a cost-effective transition to net-zero under which rate increases and potential pricing volatility can be minimized for ratepayers. Gas-fired generation will also be beneficial for grid reliability and peaking support, which will support investment in, and rapid deployment of, renewable energy resources.

3. What would be an acceptable end-point emissions intensity standard to achieve the objective of the CES?

Enbridge does not have a specific number to share at this time, though we look forward to ongoing discussions on this question. The 2035 "net-zero" emissions intensity standard should not be more stringent than a natural gas plant with 95% CCUS, as anything more stringent could artificially force low-emitting gas off the grid, resulting in stranded assets, higher consumer rates, and reliability impacts. Natural gas power plants equipped with CCUS are unique among power generating resources in their potential ability to deliver net-negative carbon reductions where they may also be supplied with RNG. Furthermore, supplying RNG to natural gas power plants represents an immediate opportunity to reduce emissions from the electricity sector without requiring investments in new generation capacity or retrofitting.

4. How do considerations differ for non-competitive electricity markets, vertically integrated utilities, etc.?

Most Canadian provincial and territorial markets have limited merchant/competitive market opportunities, or none at all. All markets and utilities should be treated the same under the CES, though we acknowledge that remote and Indigenous markets may require some additional support and/or transition allowances and considerations, which we would support.

Compliance Flexibilities

5. Should the CES offer compliance flexibilities?
   - **a. What kinds of flexibilities?**
   - **b. Should the flexibilities be targeted to individual generating units? To corporate fleets of units, such as fleet averaging, etc.?**
   - **c. What constraints or limitations should be incorporated into flexibilities?**

The CES should permit compliance via several means, including,

- Adoption and development of non-emitting resources;
- Efficiency and/or operational retrofits and updates that reduce generating unit emissions;

- Retrofits and/or adoption of emissions removal technologies like CCUS;
- Incorporation of fuels that reduce emissions, e.g., hydrogen and RNG blending;
- Offsets; and
- Compliance payments.

Provinces and territories should have the flexibility to establish their own programs insofar as they would result in the same emissions reductions and net-zero end goal as the Federal CES. The compliance options above should be available in some form in all jurisdictions and should be available at the smallest compliance reporting unit under the federal or provincial rules to ensure absolute emissions reductions. The flexibilities and various compliance mechanisms should be made increasingly stringent to ensure Canada's grid stays on a steady path toward net-zero in 2035.

Provinces and territories should be able to further provide flexibility on compliance to specific generating units where there are uncommon technical, logistical, or economical barriers to compliance and where the impact to the grid of that resource leaving the grid would have immediate and significant rate and/or reliability impacts for ratepayers. Development of electricity generation resources is a years' long endeavour, even for resources with shorter development windows, due to challenging permitting environments in some areas. This is especially true where some of the technology is just now emerging. Provinces and territories working together with market administrators should have the flexibility to provide temporary, short-term compliance flexibility to a resource where it is needed to fill a gap prior to new resources or technologies coming online, especially during the transition period. This will help calm concerns about potential price volatility and/or reliability issues, which will provide certainty needed for other industries looking to invest in Canada and establish operations during this transition period.

6. **Under what conditions should offset credits available through federal, provincial/territorial, or other programs be permitted?**

   To ensure that current investments are not stranded, projects currently generating emissions reductions under provincial and territorial programs should be eligible to generate offsets, insofar they are compliant with those programs. Renewable generators should receive free emission allocations for the power produced by their renewable energy assets under OBPS in order to access the same benefits as coal and natural gas plants, which are set to receive allocations until 2030. This approach has worked well in Alberta in properly valuing various technologies with consideration for their emissions.

   During the transition period, generators subject to increasingly stringent performance standards should be able to generate surplus credits for performance improvements, including adoption of CCUS technology, alternative fuels (hydrogen and RNG) blending, and/or technical and operational changes that result in reduced emissions.

   The standards to generate offsets should be established at the time of investment and applied over a fixed period of time, e.g., number of years, for a project to incentivize adoption of these technologies and provide revenue certainty. However, the standard for offsets earned should be increasingly tightened for new projects coming online to ensure real emissions reductions occur as technology matures and we near 2035. For newer technologies, initial offset rates could be maintained until the technology reaches a particular penetration rate. In all cases, offset rules should ensure that non-emitting sources are not at a disadvantage and, therefore, artificially undervalued as they are under the OBPS today.

In addition, as noted above, offset use should be capped to ensure that it does not undermine the economics of investing in these emission-reducing changes.

7. **To what extent can negative emission technologies like BECCS and DAC contribute to meeting the obligations of a CES regulation? To what extent should they be allowed to contribute to meeting those obligations?**

   These technologies are emerging, but we anticipate they will play an important role in meeting Canada's net-zero targets for its grid and broader net-zero targets. Enbridge looks forward to the GoC providing more detail on what these compliance pathways could look like.

8. **Should compliance be assessed for the electricity sector on an annual or multi-year basis?**

   Compliance should be assessed on an annual basis, in keeping with the OBPS and existing provincial programs.

Alignment with Carbon Pricing

9. **Should the way in which electricity generation is currently treated by carbon pricing be changed to facilitate achieving NZ2035?**

   Renewable energy in provinces and territories currently under the federal backstop should be able to opt-in to the carbon pricing system under OBPS. Currently, coal and gas receive allocations that are not accessible to renewables which creates an unfair economical advantage. For example, in Alberta where renewables can participate in TIER, renewable energy investment is increasing rapidly on an annual basis.

10. **How might the treatment of electricity under the OBPS have to change to align with the CES?**

    Under OBPS, the allocations for all electricity resources should be gradually reduced to zero by 2035, and should be a requirement for provinces and territories to establish or continue operating their own programs in place of the federal backstop.

Treatment of Natural Gas Generation

11. **What is the role of natural gas in a net-zero electricity sector before 2035? Post-2035?**

    Abundant, low-cost natural gas and a deeply-integrated North American energy market is a key advantage. The natural gas industry has already made significant strides across the value chain to reduce emissions. Canadian LNG, for instance, is among the cleanest in the world as a result of using hydroelectricity for power. Using LNG for electricity generation is expected to result in an estimated 45% reduction in GHG emissions compared to coal. In addition, supplying RNG to natural gas power plants represents an immediate opportunity to reduce emissions from the electricity sector without requiring investments in new generation capacity or retrofitting. Natural gas will play a pivotal role in underpinning renewable energy globally in the long-term while immediately replacing coal powered electricity.

    It is critical to take a "whole energy sector" view when it comes to energy markets as much as possible. For example, the degree to which heating and industrial uses can be economically electrified will be a major determining factor in how the electricity sector demand and specific needs develop over the coming decades as we move toward a net-zero economy in 2050. Looking at the electricity sector in isolation could result in incomplete planning and uneconomical approaches to net-zero.

In the case of the electricity sector, existing (and near-term new) natural gas paired with CCUS and/or blended with non-emitting fuels like hydrogen and RNG, will be a reliable, economical source of electricity that can support increased adoption of renewable energy and power storage resources, as Canada's electricity demand grows. In addition, provinces and territories should have the authority to move toward the net-zero by 2035 requirement at a pace that ensures reliability and minimizes cost of power increases, which may include continued use of unmitigated natural gas in the near-term.

Major power consumers spending hundreds of millions of dollars on power, as well as families on a tight monthly budget would all be impacted by even relatively small 5%-10% price increases. Price uncertainty and/or increases could create operational cost uncertainty and deter new investment from other industries considering Canada for their operations. A strategic and thoughtful, regional approach to natural gas before and after 2035 will maximize reliability and cost management benefits for Canadians, while keeping all regions on track toward net-zero by 2035.

Natural gas also has multiple pathways toward operating as a low-emitting source of power. The GoC's CCUS ITC as proposed in its 2022 budget, and its plan to develop an ITC for clean hydrogen, along with support for RNG development will help these technologies mature and will result in lower per-unit costs. These technologies will enable natural gas to remain on the grid while still reducing emissions and will minimize stranded assets and transition costs for ratepayers.

Use of these existing gas resources will also provide support for the anticipated boom in renewable energy investment needed to meet Canada's net-zero targets, while power storage technologies undergo their own maturation and cost reductions. The GoC's proposed plan to implement a battery power storage ITC will further accelerate these cost reductions and technology improvements.

12. **What flexibility should be allowed to use natural gas to maintain reliability in rare and extreme weather, emergencies, or other special circumstances? Which additional operating conditions/scenarios, if any, should be given special consideration?**
    a. **If natural gas has an electricity system-support role post-2035, what are the expected impacts on the rollout of emerging system support technologies such as energy storage?**
    b. **If natural gas has a role in generation post-2035, what are the expected impacts on the penetration of nascent generation technologies like SMRs, geothermal electricity, etc.?**

Natural gas-fired generation, paired with CCUS should be considered a low-emitting electricity resource, or even a non-emitting or negative-emission resource if CCUS is paired with RNG or green hydrogen blending. Gas' ability to provide power during weather extremes and other special circumstances is an important benefit of gas (depending on the weather extreme, e.g., solar may be as reliable a resource during a long hot summer), but it is not the only reason to keep natural gas on the grid. In the event CES enables low-emitting gas-fired generation to remain part of Canada's energy mix beyond 2035, there would be no need for special considerations.

As described above, Enbridge supports an "all solutions" approach to net-zero where the GoC and provinces/territories do not pick one low-emission solution over another. Wind and solar power are two of only a very few, non-emitting resources available in Canada. Wind and solar are the lowest cost electricity of any kind in Canada due to decades of technology improvements. Solar paired with battery power storage is also on track to be less expensive than natural gas (without CCUS) in the very near future. As a result, wind and solar, with power storage, will be the lowest-emission, lowest-cost resources available and they will thrive where there are no artificial barriers to their development established by provincial/territorial governments, regardless of low-emitting gas' smaller ongoing role on the grid. Wind and solar will also be able to pair with other forms of power storage that will become increasingly cost-competitive over time, including pumped hydro, hydrogen, and new emerging technologies, which will enable longer-term storage options for emission-free renewable power.

It will be important to consider the whole cost of power in system planning as well, e.g., including the cost of transmission, which will help ensure that non-wires alternatives, self-supply, and demand management technologies are properly valued and fully enabled under provincial regulations.

Policies should focus on ensuring the renewable resources have equal access to procurement processes and interconnections, receive allocations under the OBPS, and receive ITCs for power storage projects, as set out in the GoC's 2022 budget. In all cases, GoC's support of natural gas, CCUS, hydrogen, and RNG could be maintained, as part of the "all solutions" approach.

Treatment of Industry, Private Generation and Remote Generation

13. **How should the CES treat electricity generated by cogeneration units that is sold to the electricity system? Should the CES apply fully to cogeneration units by 2035 or should it phase-in its application to cogeneration units after 2035?**

    Enbridge submits that cogeneration is typically a relatively (to other fossil fuel-based generation) low-emitting generation resource. It is also cost-efficient, which helps keep rates affordable for large power consumers and residential ratepayers alike. Emissions from cogeneration must be captured as part of the broader net-zero economy by 2050 framework, but that it is important that the emissions are captured under the correct framework, e.g., OBPS or CES, at the right time, and that the compliance requirements are established with regional consideration of available alternatives, costs, emissions reductions, and other goals. For example, it is not necessary to resolve all net-zero questions at this time, and cogeneration, along with biomass and remote generation, could be addressed once the larger standards and compliance mechanisms are established.

14. **What are the benefits of applying a CES to industrial generation units? What are the challenges of doing so? Of not doing so?**

    See above.

15. **How should the CES consider electricity generation in remote, northern, and Indigenous communities?**

    No comment at this time.

16. **How should the CES consider distributed energy resources?**

Distributed energy resources encompass many different forms of electricity resources, so we have divided the category into subcategories below for clarity.

Enbridge submits that distributed energy resources generating electricity, e.g., behind the meter (BTM) power projects, distribution connected generation, etc., should be subject to the same CES requirements as other electricity generation resources. To do otherwise under the CES could see higher-emitting resources move behind the meter instead of taking steps to reduce emissions via CCUS and/or fuel blending, or transition to renewable resources.

To the extent this question refers to distributed energy resources providing demand response and other demand side services, but not generating electricity on their own, they should not be required to comply with the CES as they are only storing and disbursing electricity already generated elsewhere. However, we submit that demand-side programs could be eligible to generate offsets under clearly defined protocols that avoid double-counting with offsets and/or other credits generated under other programs like OBPS, Clean Fuels Regulation, or others that may be established at the provincial or federal level.

Treatment of Biomass

17. **If CO_2 emissions from biomass combustion are not counted towards compliance under a CES, to what degree might biomass generation increase?**
18. **What types of biomass are suited to electricity generation? What are their characteristics with respect to regenerative life cycle, non-CO_2 GHG emissions, and land use characteristics?**
19. **What emissions reporting and compliance requirements for biomass generation should be considered to ensure that nature is protected and land-based emissions do not increase?**

No comment at this time.

Other Questions

20. **What additional investments are anticipated to be necessary to achieve NZ2035 to help ensure affordability for consumers?**

Enbridge supports the GoC's spending announcements to date, including its 2022 budget plan, and the additional spending set out in its Emissions Reduction Plan. The ITCs for CCUS, clean hydrogen, and power storage will play a critical role in supporting development of new projects in these emerging technologies, which will help them mature and lower per-unit costs more rapidly. This will help avoid stranded assets and will maximize use of existing infrastructure which will minimize the transition cost for ratepayers. These incentives will also help position Canada as a leader in these important net-zero technologies, which could provide important economic and employment opportunities for Canadians, including creation of technology and/or manufacturing hubs in Canada.

A transmission ITC could also help support the transmission development GoC proposed between provinces, especially if also paired with permitting and regulatory frameworks and backstops at the federal level for inter-jurisdictional connections.

The provinces and territories' adoption of clear regulations and market mechanisms in support of grid modernization (including power storage) will also be critical in ensuring that the lowest-cost solutions are incorporated into the grid transition to net-zero.

Finally, clear, long-term market and policy signals will provide the certainty needed to minimize cost of capital for new development and/or retrofits of all kinds. This is a critical means of ensuring that electricity remains affordable for Canadian ratepayers.

21. What role could existing and expanded energy efficiency programming play in helping to meet new demand as they transition towards net-zero 2035? What are the constraints for additional efficiency measures? Technological? Policy? Other?

The cleanest source of electricity is electricity not used. Energy efficiency programming will play a key role in meeting new demand by offsetting it with reductions elsewhere on the grid. Public awareness campaigns, support for smart grid and other grid modernization technologies, ITCs for energy efficiency investments, retrofits, etc., could go a long way toward improving and incentivizing adoption.

22. What other factors should the government consider in developing the CES?

We understand the details in Annex A, Table 1 were taken from EIA and IEA reports but the development lead times on certain technologies (e.g., SMRs, large hydro, large nuclear) are optimistic and even the wind and solar lead times are too short for certain jurisdictions in Canada where permitting and interconnection challenges make for longer development and construction periods. We suggest that the GoC work with (and possibly provide financial support for) provincial and territorial governments to improve permitting efficiency.

Enbridge believes it is also optimistic to list SMRs at a level 6-9 in the technology readiness analysis given that offshore and onshore wind, and PV solar are also listed at level 9. For example, there are over 16 GW of wind and solar installed in Canada alone and, to Enbridge's knowledge, no SMR capacity installed. We submit SMRs should be listed at the levels of natural gas plus CCUS as an upper limit, i.e., level 5-6. A reasonable assessment about the readiness and affordability of technologies is important to ensure that existing power supply is not scheduled for removal from the grid artificially early in the pathways to net-zero planning processes, as such actions could lead to reliability issues and price increases.

Finally, transparent, timely, and accessible inventory reporting will be critical to ensure we meet the targets, and to help customers, utilities, and power generators make their respective investment and market participation determinations in an informed and efficient manner that minimizes avoidable costs.

Conclusion

Thank you for this opportunity to provide input on the Clean Electricity Standard. If you have any questions, please do not hesitate to contact amanda.affonso@enbridge.com

Written Submission on Clean Electricity Regulations Framework

Submitted by Enbridge

August 17, 2022

About Enbridge

Enbridge Inc. is a leading North American energy infrastructure company. Our core businesses include Liquids Pipelines, which transports about 30% of the crude oil produced in North America; Gas Transmission and Midstream, which transports about 20% of the natural gas consumed in the U.S.; Gas Distribution and Storage, which serves approximately 3.9 million retail customers in Ontario and Quebec; and Renewable Power Generation, which has more than 1,766 megawatts (net) in operating renewable power generation capacity in North America and Europe. We appreciate the opportunity to provide comments on the Government of Canada's (GoC) "Proposed Frame for the Clean Electricity Regulations" (CER).

Introduction

Enbridge supports the GoC's goals of achieving a net-zero economy by 2050. We have adopted strong greenhouse gas (GHG) emissions reduction targets at our company as part of our larger Environment, Social and Governance plan, including elimination of GHG emissions from our operations on a net basis (net-zero) by 2050 with an interim emissions intensity reduction target of 35% by 2030. We further support GoC establishing clear regulations and market signals now, given the long timelines for infrastructure development in the electricity sector and in the provincial regulatory frameworks required to support a net-zero grid by 2035. This proactive approach will help ensure that the transition is cost-efficient for ratepayers across the country by providing the policy certainty needed to inform business decision making.

Enbridge agrees with the GoC's three key pillars of its CER framework, including GHG emissions reductions, reliability, and affordability, and its "all solutions" approach. Renewable energy and power storage will play a major role, but to meet net-zero these resources must be supported by natural gas, including when paired with carbon capture, utilization, and storage (CCUS), along with clean hydrogen, renewable natural gas (RNG), and waste heat resources, and others. This includes new unabated natural gas-fired generation, particularly in the western prairie provinces, for the coming years. Regulations and enabling standards developed through this consultation should work to balance the three key pillars, while providing developers of all technologies the clarity and regulatory certainty needed to make the necessary investments. We recommend that a guiding principle for the CER should be to adopt policies that incentivize early-action from those with emitting resources in their fleet, as detailed below.

Canada has excellent resources and infrastructure and is well-positioned to meet the challenge of moving to a net-zero electricity grid. However, recent global developments, including Europe's move to reduce its dependence on Russian natural gas and the passage of the *Inflation Reduction Act* in the United States, will put incredible pressure on the economics of building in Canada. Incentives and new supply chains focused outside of Canada will provide strong competition for investment dollars and may divert financial and development resources. GoC has already proposed and is in development of key initiatives that would help overcome this competitive disadvantage, including the tax credits for CCUS, power storage and clean hydrogen, and we encourage GoC to complete work on those tax credits as soon as possible. We further support the GoC's proposal to develop new interties between provinces, e.g., the Atlantic Loop project and its announced spending on smart renewable energy and grid technologies, and remote and Indigenous clean energy projects. Finally, we recommend that GoC consider tax credits for transmission development and RNG to help advance much needed projects in support of net-zero objectives. These tax credits and other programs will provide critical financial support for emerging technologies that will play a major role in Canada's net-zero grid future.

We have provided detailed comments on GoC's proposal details below, including:

- GoC should provide more specific detail on several items, including a definition of "emergency," anticipated carbon pricing beyond 2030, and standards for new gas coming online post-2022.
- GoC should complement tax credits for hydrogen, CCUS, and power storage with incentives for early action including the ability to generate and carry forward credits for meeting CER standards even if not yet subject to CER, and special incentives and/or tax credits for negative emission technologies (e.g., RNG)
- CER should cover generating resources not already covered under other regulatory frameworks and/or if CER becomes the default regulatory framework to cover all electricity generation, the rules by which certain existing assets are moved from under existing emissions regulation frameworks must be done in a way that does not penalize those relying on Behind-the-Meter (BTM) generation and/or cogeneration for compliance with other regulations.
- The prescribed life – or the period during which gas reaching commercial operation prior to 2025 can continue to operate unabated – should be at least 20 years, in keeping with typical commercial assumptions.
- GoC should establish a market mechanism linked with Canada's Offset Credit System to maximize use of the existing system and fungibility of credits created under CER. This should also be interoperable with provincial and international (including US) systems.

Enbridge looks forward to continuing participation in CER consultations in the coming months.

Comments on Framework

Scope of application

The CER would regulate emissions of carbon dioxide (CO_2) from electricity generating units that meet all of the following criteria:

- *Combust any amount of fossil fuel for the purpose of generating electricity;*
- *Have a capacity above a small megawatt (MW) threshold (value to be determined); and*
- *Offer electricity for sale onto a regulated electricity system.*

Enbridge generally supports the proposed scope of application. It is our understanding from GoC's webinar that the small MW threshold being considered is smaller than 250 kW. We would also support exemptions for projects at some MW threshold below that size, with consideration for the tonnes of carbon dioxide equivalent (tCO2e) emitted by the facility, to ensure that smaller facilities are not expected to invest in potentially costly retrofit technologies to avoid only small GHG emissions volumes.

We further support focusing on Front-of-the-Meter development, insofar as Behind-the-Meter (BTM) development is captured under other GHG emissions regulations such as OBPS and/or CFR, and insofar as the standards under those programs are as stringent as the CER with the same options to generate offsets and/or performance credits for GHG emissions reductions, e.g., swapping natural gas-fired co-gen for BTM solar.

Proposed emissions standard

- *The CER would establish an emissions performance standard having an intensity form (i.e., t/GWh). It would be set at a stringent, near-zero value in line with direct emissions from well-performing, low-emitting generation such as, geothermal or combined cycle natural gas with CCS.*
- *A regulated unit would be prohibited from operating when its quantified emissions performance exceeds the applicable standard over a period of time.*
- *Any residual emissions below the standard would be subject to financial compliance requirements, such as offset purchases.*
- *Some exemptions are proposed.*

Enbridge generally supports the proposed emissions performance standard of a near-zero value in line with low-emitting generation such as geothermal or natural gas combined cycle with CCS. This will encourage adoption of non-emitting sources such as wind, solar, offshore wind, clean hydrogen, and RNG-fired generation, while still providing room for conventional natural gas to continue playing a key role in system reliability for years to come where it is paired with CCUS and/or other abatement technologies.

As clean hydrogen, RNG, and power storage technologies mature, and particularly as carbon capture, use and storage technologies are scaled-up and become more widespread, it may be possible to increasingly tighten the GHG emissions performance standard to ensure that the grid continues to move as close to zero emissions as possible in a way that does not lead to significant price increases for Canadian ratepayers. We reiterate our support for GoC's tax credits and other financial programs to support development of clean hydrogen, RNG, CCUS, and power storage, and encourage GoC to make sure these incentives and funding programs are competitive with those in the United States and elsewhere to keep the investment and development resources in Canada and to help these technologies and Canadian markets mature.

Affordability and Reliability

To support affordability and reliability while achieving net zero, the following approaches are proposed:

- *Compliance can be achieved through a variety of technologies, and the regulations will be technology-neutral, e.g., co-firing fossil fuels with non-emitting fuels, completely switching to these non-emitting fuels, such as hydrogen, ceasing operations, and/or installing abatement technologies. The regulations will not be prescriptive on which approach should be taken.*
    - *A phase-in of the CER requirements would allow newer natural gas units built prior to the CER publication date to operate past 2035 for a short, prescribed period.*
- *Unabated natural gas would be allowed during emergency circumstances.*
- *Existing units that have reached their end of prescribed life could continue to generate electricity to provide backup to variable renewable electricity if they meet the following conditions:*
    - *They emit less than [TBD] kilotonnes per year; and*
    - *They operate less than [TBD] number of hours per year.*

Enbridge supports GoC's efforts to provide compliance flexibility to ensure affordability and reliability of Canada's electricity systems are maintained for energy consumers.

A CER framework that does not address regional variability could disproportionally impact some provinces more than others. We understand from the GoC's webinar that the Government's analysis concluded Alberta is not in a position to transition directly from coal to all renewables, and that new natural gas-fired generation will be required in the coming years to enable the province's transition to a low-emitting and eventually net-zero electricity system, while maintaining reliability and affordability. The proposed "prescribed life" will help support system reliability while moving Canada steadily toward a net-zero grid. Similarly, other provinces may have difficulty meeting the requirements of the proposed CER while maintaining electricity affordability and reliability. Enbridge supports an "all solutions" approach to ensure that all commercially available technologies can be used as suits each region to meet the energy, capacity, and resiliency needs of an affordable and reliable grid. This would include renewables, power storage, hydrogen, RNG, CCUS, and – for a prescribed time and in emergency circumstances – unabated gas, as proposed by GoC.

The ability to provide energy when consumers need it, including on the hottest and coldest days of the year, and when extreme weather events occur, is critical. ERCOT's experience in Texas demonstrated on many levels that a lack of reliability in electricity and gas supply can have significant economic and human health and safety impacts. Enbridge supports the provision that natural gas would be allowed in emergency circumstances, however there are practical realities that need to be considered to support this provision. For natural gas to act as an emergency generation source, access to natural gas assets, including transmission, storage, and distribution assets, needs to be available. These assets will not be held available as an option for power generators to use when they see fit. Access to the capacity required for power generation is held under firm contracts, and any excess capacity on the natural gas system will be sold to the broader the market. Power generators will need a market mechanism to allow them to sign-up for these services, so they are available when called upon to produce power. Additionally, there will be a need to run gas-fired assets periodically to ensure they are functional when called on in an emergency. Allowances should be made to allow gas-fired generation to run on a regular basis to ensure those assets are available in emergency circumstances, as below.

More clarity in standards and definitions under these parts of the CER, will allow more affordability benefits to be realized. For example, investors in all generation technologies will require certainty about the intent, limits, and effect of the regulations to investment in new sources of electricity generation, transmission, and storage projects.

As a result, Enbridge recommends:

- To ensure compliance flexibility will truly be available, GoC should review the technology readiness and feasibility of the various technologies that could be used to achieve compliance, as well as the technologies that will be relied upon to replace gas-fired generation. For example, hydrogen-ready turbines (new and/or retrofit) and Small Modular Reactors (SMRs) will likley be available in time, but the timing should be more specifically forecast along with anticipated, related costs.
- To avoid disproportionally impacting jurisdictions, a jurisdictional lens should be placed on the technology evaluation, as technologies that are feasible in one jurisdiction may not be feasible in another. Additionally, Enbridge suggests regional discussions be held for each province, which should include both ECCC and NRCan, as well as members of provincial government, electricity system operators, and other relevant stakeholders.

- GoC provide a more direct and specific definition that is less open to interpretation, on a facility-by-facility and system operator basis, of “extraordinary, unforeseen and irresistible” for “emergency.” We agree with the Canadian Renewable Energy Association (CanREA) that the North American Electric Reliability Corporation (NERC) standard definition of emergency is familiar to all generators and could provide a clear and consistent definition.
- To ensure gas-fired assets are available in emergency circumstances, GoC should provide an exemption that allows gas-fired assets to be run on a regular basis. Reasonable limits for this exemption should be set through public consultation.
- The “prescribed life” should be set to at least 20 years, which is a standard initial operating period for most generation projects. It is shorter than some technologies but long enough to ensure a reasonable rate of return and to investigate potential retrofit technology options. The prescribed life would start on the commissioning date, e.g., the date of the facilities first sale of electricity to the electricity system. The CER would then apply to a facility entering operation before 2025 at the later of 2035 or the end of the Prescribed Life. Enbridge also suggests that the term “Prescribed Life” could be more aligned with its intent. Enbridge suggests the term “Unabated Life” is as a more accurate term and would avoid any confusion from the term “Prescribed Life” which could be misinterpreted as limiting the operational life of fossil fuel power generating assets.
- GoC could also establish incentives to encourage emitting facilities to reduce GHG emissions in advance of the 2035 CER-applicability deadline, e.g., by allowing them to generate offsets and/or performance credits once they drop below a best-gas threshold in effect in any year before the end of their prescribed life and permit those generators to sell the credits and/or to carry them forward to be used in their own early compliance periods. This could incentivize early development of RNG, clean hydrogen capacity and increased investments in CCUS, which will also help other parts of Canada’s net-zero economy.
- GoC should provide clarity on anticipated carbon pricing between 2030 and 2035, and beyond if possible. This will be a crucial financial input to investment decisions and planning.

Proposed Implementation Approach and Associated Dates – New Units

Treatment of all units firing gaseous, liquid, or solid fossil fuels

- *A unit commissioned in 2025 or after would be subject to current electricity sector policies (the federal phase-out regulations for unabated coal, the federal performance standards for new natural gas, and carbon pricing) until January 1, 2035. Starting on January 1, 2035, the CER and its performance standards and the associated financial compliance component would replace current electricity sector policies.*
- *While the CER limits would only become binding in 2035, it is expected that they will deter any unabated new fossil fuel-fired generation in Canada. The decision to commission a new unit after 2025 will need to take into consideration the CER obligations. As continued operation after 2035 will require the installation of abatement technology, these units will need to resolve the financial implications of having to comply with the CER obligations even in their initial project development.*

Enbridge supports GoC’s proposal on the treatment of new gas before and after 2035. As noted above, we recommend:

- GoC could establish financial incentives to encourage emitting facilities to reduce GHG emissions in advance of the 2035 CER-applicability deadline, e.g., by allowing them to generate offsets and/or performance credits once they drop below a best-gas threshold in effect in any year before the end of their prescribed life. These offsets and/or performance credits could be sold to other emitters with compliance requirements and/or retained for compliance obligations post-2035, subject to broader longevity rules established for offsets under the CER.
- GoC should provide clarity on anticipated carbon pricing between 2030 and 2035 (and beyond). This will be a crucial financial input to investment decisions and planning.

Proposed Implementation Approach and Associated Dates – Existing Units

Treatment of all units firing gaseous, liquid, or solid fossil fuels

- *A unit commissioned before 2025 would become subject to the CER's emission intensity performance standard at the end of its prescribed life, or, on January 1, 2035.*
- *The definition of prescribed life is a topic that requires further consideration. It could be defined as a period of fixed years starting with its commissioning date, i.e., the date of its first sale of electricity to the electricity system.*
- *An existing unit would be subject to current electricity sector policies until it becomes subject to the CER and its performance standard.*

Enbridge recommends that the prescribed life be set at a minimum 20 years from the date of commercial operation to ensure that generators can recover their investment without increasing electricity prices while also ensuring that the emitting sources do not linger on the grid. The GoC could provide incentives for existing generation to reduce GHG emissions in advance of the end of their prescribed life by making them eligible to generate performance credits and offsets to some degree if they can reduce GHG emissions below a specific threshold, e.g., best gas in the particular year or some reduced level from best gas, as they move toward the CER-applicability deadline at the end of their prescribed life. These generators could then sell the credits to other emitters or carry them forward to their own early-compliance periods. This could encourage early development of RNG and/or clean hydrogen capacity and CCS projects, which will also help reduce GHG emissions in other parts of Canada's energy sector.

Proposed requirements for financial compliance for all emissions below the regulatory limit

- *In addition to ensuring that all regulated units operate within the stipulated limits, regulated units would be required to compensate for any emissions released to the environment.*
- *This requirement would begin in 2035 for both new units and existing units, as defined above.*
- *The eligible forms of financial compliance are to be determined but could include the production or purchase of prescribed high quality offsets, including verified negative emissions, or paying an amount that corresponds to the federal carbon price for the relevant compliance period.*
- *Emissions for units operated in emergency situations would be exempt from financial compliance requirements.*

Enbridge generally supports this proposal, subject to our recommendations above.

In addition, we recommend that a CER-based market mechanism be linked with Canada's GHG Offset Credit System to enable greater fungibility and opportunities to mobilize reinvestment in the further decarbonization of the grid. This would also avoid the necessity to establish an entirely new, stand-alone market and leverage existing regulations, quantification methodologies, etc. We also believe that the inclusion of verified negative emissions (i.e., direct air capture and nature-based solutions) requires a linkage with a broader carbon market as these types of projects would not likely occur within the context of the CER.

Finally, recognizing that the CER is intent on achieving a net-zero grid we recommend that credit usage limits be enacted with a decreasing trajectory to ensure that absolute GHG emissions reductions occur.

Potential compliance flexibility

The use of fleet averaging approaches could ease compliance burdens and incentivize the build out of renewables.

Enbridge generally agrees that fleet averaging approaches could ease compliance burdens and incentivize build out of renewables, CCS, power storage, clean hydrogen and RNG technologies. However, it should not enable the largest generators to continue emitting while generators with smaller portfolios are left to carry most of the responsibility for reducing GHG emissions. It should also not force generators to aggregate or impose unfair disadvantages on those who do not, reducing competition in Canada's electricity markets. We look forward to ongoing discussions with GoC on this topic.

Proposed treatment of industrial units

- *The CER would only regulate industrial units (including cogeneration) that offer electricity for sale to the electricity system.*
- *The CER would not generally regulate a cogeneration unit that generates electricity for its own needs, i.e., "self-consumption" of electricity generated and consumed behind the industrial fence line. Other regulatory and pricing measures would continue to apply to those emissions.*
- *This treatment of cogeneration units could be revisited later. The CER could then potentially require all cogeneration units to meet the same standards as those units offering electricity for sale to the electricity system.*

Enbridge generally supports GoC's proposal insofar as industrial units are captured under other regulatory regimes, e.g., OBPS, and that those regulatory regimes are as stringent as the CER. This will enable operators to make the most economic investment decisions, preserving affordability and reliability, while still resulting in meaningful GHG emissions reductions. We further agree that issue should be revisited to avoid unintended consequences of the proposal that could undermine the CER.

Proposed exemptions from the CER performance standards for regulated units

The CER would allow for two categories of exemptions:

- *Units would be allowed to supply electricity to the electricity system without having to meet either a performance standard or the requirement for financial compensation for emissions during emergency circumstances, which are defined as "extraordinary, unforeseen and irresistible."*
- *Units operating in areas not connected to an electricity system regulated by the North American Electric Reliability Corporation ("NERC") would be exempted. These areas are predominately remote, Northern or on federal lands.*

Enbridge generally agrees with GoC's proposal, subject to the clarifications requested above, including:

- GoC should provide a more direct and specific definition that is less open to interpretation, on a facility-by-facility and system operator basis, of "extraordinary, unforeseen and irresistible" for "emergency." We agree with CanREA that the NERC standard definition of emergency is familiar to all generators and could provide a clear, consistent definition.
- GoC should provide reasonable limits on natural gas-fired generation during emergency events instead of allowing completely unabated production. There may be non-emitting resources available for electricity generation during emergency events that could be uneconomical compared to non-emitting natural gas but that would still be economical for ratepayers. Insofar as there would not be a significant ratepayer impact, the non-emitting resources should continue to be relied upon and prioritized during emergency events.
- We reiterate that gas will need to be run regularly, subject to reasonable limits to be determined via public consultation, in order to ensure that the gas system (including storage, transmission, etc.) is in working order and available during emergency events.

Conclusion

Thank you for this opportunity to provide input on the Clean Electricity Regulations. If you have any questions, please do not hesitate to contact amanda.affonso@enbridge.com

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 3, Page 2

Preamble:

“6. Ontario’s GHG emissions in 2020, the last year for which data are publicly available, were 150 million tCO2e. Enbridge Gas’s scope 1 and 2 emissions are less than 1% of Ontario’s GHG emissions and the scope 3 GHG emissions from combustion of natural gas by Enbridge Gas’s end-use customers are approximately 32% of Ontario’s emissions.2 Enbridge Gas’s scope 3 GHG emissions by sector are provided in Figure 1.”

Question(s):

a) Please confirm that the emissions referred to above do not include the upstream emissions from the extraction of gas at its source and transportation to Ontario.

b) Please provide Enbridge’s best estimate of the upstream carbon emissions (tCO2e/m3) attributable to Ontario’s gas consumption. As Ontario’s gas comes from a variety of sources, please provide a best estimate with any necessary caveats. Please also provide the underlying calculations, such as the upstream emission intensity. Please also provide a high and low range estimate of this figure representing the differing scientific views on the upstream carbon emissions.

   This is relevant, among other things, to the probability that the lifecycle carbon emissions from gas will result in policies and market forces that significant reduce or eliminate gas consumption before the end of the life of assets to be built during the rate period.

c) Please also provide the gross upstream carbon emissions associated with Ontario’s total gas consumption (tCO2e).

d) Please provide the total non-rounded Ontario 2020 GHG emissions (tCO2e) and the combined Enbridge scope 1, 2, and 3 emissions.

Response:

a) Confirmed.

b-c) Enbridge Gas does not calculate the upstream carbon emissions attributable to Ontario's gas consumption and therefore does not have the requested data.

d) Ontario's 2020 GHG Emissions were sourced from Table A11-13 of the National Inventory Report 1990-2020[1] and are presented as rounded numbers in that report.

The non-rounded 2021 Enbridge Gas combined scope 1, 2, and 3 emissions are provided in the table below:

Emissions Category	2021 Emissions (tCO_2e)
Scope 1	888,654
Scope 2	1,026
Scope 3	48,324,031
Total	49,243,711

[1] National Inventory Report 1990 – 2020: Greenhouse Gas Sources and Sinks in Canada, April 14, 2022, Part 3, p.27, https://unfccc.int/documents/461919

ENBRIDGE GAS INC.

Answer to Interrogatory from Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 3, Page 2

Preamble:

Table 1
Enbridge Gas GHG Emissions (1)

Line No.	Emissions Category (2)	Description	2021 Emissions (Million tCO_2e)
1	Scope 1	Emissions from Enbridge Gas's operations: combustion, flaring, venting and fugitives	0.9
2	Scope 2	Emissions from off-site generation of electricity, which Enbridge Gas buys and consumes	0.001
3	Scope 3	Emissions from combustion of natural gas by the Company's end-use customers.	48.3
4	Total		49.2

Question(s):

a) Please confirm that scope 3 emissions also include emissions from unburned methane gas emitted by end-use customers. If not, please explain why not.

b) What definition of scope 1, 2, and 3 emissions does Enbridge use?

c) Please provide a table comparing the definition of scope 1, 2, and 3 emissions per (i) Enbridge's practices/policies, (ii) the GHG Protocol, (iii) ICO 14064, and (iv) the United Nations Framework Convention on Climate Change.

Response:

a) Confirmed. Please see response to Exhibit I.1.10-ED-12 part a).

b) As indicated in Exhibit 1, Tab 10, Schedule 3, page 2, Table 1, Note 2, Enbridge Gas follows the definitions of GHG emissions outlined in The Greenhouse Gas Protocol[1].

c) As noted above, Enbridge Gas follows the definitions outlined in the Greenhouse Gas Protocol. Please see the following links to understand the emission definitions utilized by the identified organizations. Enbridge Gas notes that each of these organizations uses different categorizations of emissions and therefore any attempt to summarize in tabular form might create inadvertent mischaracterizations.

- GHG Protocol: Please see The Greenhouse Gas Protocol, A Corporate Accounting and Reporting Standard, March 2004, p. 25, https://ghgprotocol.org/sites/default/files/standards/ghg-protocol-revised.pdf.

- ISO 14064: Please see ISO 14064-1:2018: Greenhouse gases – Part 1, Annex B, https://carbon.landleaf-tech.com/wp-content/uploads/2022/04/ISO14064-1-2018.pdf. Please note that ISO does not use the terms scope 1, 2 and 3, but instead uses categories to delineate direct and indirect emissions. Please see Annex B for definitions of ISO's emissions categories (category 1, 2, 3, 4, 5, and 6)

- United Nations Framework Convention on Climate change (UN FCCC): Please see 2006 IPCC Guidelines for National Greenhouse Gas Inventories, https://www.ipcc-nggip.iges.or.jp/public/2019rf/vol1.html. The UN FCCC guideline is designed for national emissions reporting as opposed to corporate emissions reporting. As such, although the UN FCCC guideline does use the terms direct and indirect emissions, the terms are used in a different context than in corporate inventories. The UN FCCC guideline does not use the terms scope 1, 2 and 3.

[1] The Greenhouse Gas Protocol, A Corporate Accounting and Reporting Standard, March 2004, p.25, https://ghgprotocol.org/sites/default/files/standards/ghg-protocol-revised.pdf

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 3, Page 2

Preamble:

"6. Ontario's GHG emissions in 2020, the last year for which data are publicly available, were 150 million tCO2e. Enbridge Gas's scope 1 and 2 emissions are less than 1% of Ontario's GHG emissions and the scope 3 GHG emissions from combustion of natural gas by Enbridge Gas's end-use customers are approximately 32% of Ontario's emissions.2 Enbridge Gas's scope 3 GHG emissions by sector are provided in Figure 1."

Question(s):

a) Please confirm that the emissions noted above do not include unburned methane emissions from residential natural gas appliances. If they do, please provide a breakdown.

b) Please provide Enbridge's best estimate of the unburned methane emissions from residential natural gas appliances (Ontario total, CO2e). Please make and state assumptions as necessary and include caveats as necessary.

c) If it differs from the answer to (b), please provide Enbridge's best estimate of the unburned methane emissions from residential natural gas appliances (Ontario total, CO2e) based on Zachary Merrin and Paul W. Francisco, *Unburned Methane Emissions from Residential Natural Gas Appliances* (link). Please make and state assumptions as necessary and include caveats as necessary.

d) If it differs significantly from the answer to (c), please provide Enbridge's best estimate of the unburned methane emissions from residential natural gas appliances (Ontario total, CO2e) based on Patricia M. B. Saint-Vincent and Natalie J. Pekney, *Beyond-the-Meter: Unaccounted Sources of Methane Emissions in the Natural Gas Distribution Sector* (link). Please make and state assumptions as necessary and include caveats as necessary.

e) With reference to these academic studies:

Quantifying Methane Emissions from Natural Gas Water Heaters (link)
Unburned Methane Emissions from Residential Natural Gas Appliances (link)
An Estimate of Natural Gas Methane Emissions from California Homes (link)
Beyond-the-Meter: Unaccounted Sources of Methane Emissions in the Natural Gas Distribution Sector (link)
Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes (link)

Please provide a summary table of the results indicating, where available, for each equipment type: (i) the estimated unburned methane emissions (tCO2e/m3); (ii) the estimated unburned methane emissions per year on average (t/CO2e/yr); and (iii) the estimated unburned methane emissions as a percent of gas consumption (m3/m3).

f) What is the impact of 1 m3 of methane gas combusted in Ontario (tCO2e) versus 1 m3 of methane gas emitted to the atmosphere without combustion (tCO2e).

g) Based on Enbridge's residential gas equipment survey results, please provide a table showing the number of customers with a gas: furnace, stove, tank water heater, tankless water heater, and fireplace.

h) Please file the latest copy of Enbridge's residential gas equipment survey results.

Response:

a) The Scope 1 and 2 emissions do not include emissions from residential natural gas appliances. The Scope 3 emissions do include unburned methane emissions from end-user natural gas appliances.

b) Enbridge Gas's Scope 3 emissions include only in-franchise natural gas customers in Ontario. Enbridge Gas's best estimate of the unburned methane emissions from end-use of natural gas by the Company's in-franchise natural gas customers is 0.02 million tCO_2e. This estimate is calculated based on the methane emission factor for natural gas combustion by residential, construction, commercial/institutional, and agricultural uses sourced from the Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions.[1]

c-e) Enbridge Gas does not have the required time to review the seven referenced studies for applicability to its service territory, its customers or other Enbridge Gas-specific parameters, nor to review the referenced studies to understand the manner in which assumptions are made and calculations are determined. Enbridge Gas therefore declines to produce the requested calculations.

f) When 1 m^3 of natural gas is combusted, 0.001874 tCO_2e emissions are released[2], while 1 m^3 of methane emitted to the atmosphere without combustion is equal to 0.016 tCO_2e. Enbridge Gas notes that starting in 2022, the Company has updated the emission factor used for combustion of natural gas to the factors in the National Inventory Report. Please see response at Exhibit I.4.2-ED-132, part c). Using the new factor, when 1 m^3 of natural gas is combusted, 0.001932 tCO_2e emissions are released. There is no change to the emissions impact of 1 m^3 of methane emitted without combustion.

g) The percentage figures in Table 1 are based on the 2022 Residential Single Family Natural Gas End Use Study and are applied to 3.8 million residential customers.

Table 1
Number of Residential Customers with Specified Natural Gas Applications

#	Natural Gas Application	Proportion	Approximate number of customers
1	Natural Gas Home Heating[3]	94%	3,572,000
2	Natural Gas Cooking[4]	31%	1,178,000
3	Natural Gas Water Heater (tank)[5]	72%	2,736,000
4	Natural Gas Water Heater (tankless)	11%	418,000
5	Natural Gas Fireplace	35%	1,330,000

[1] Ontario Ministry of the Environment and Climate Change. (2017, November). Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions. Table 20-3 and Table 20-4. https://prod-environmental-registry.s3.amazonaws.com/2018-01/013-1457_d_Guide.pdf.
[2] Using the emission factor referenced for the calculation of 2021 Scope 3 emissions in Exhibit 1, Tab 10, Schedule 3, pages 2.
[3] Please see a more detailed breakdown of home heating equipment on page 7 of the 2022 Residential Single Family End Use (REUS) report.
[4] Please see a more detailed breakdown of cooking equipment on page 17 of the 2022 REUS report.
[5] The tank and tankless proportions in this table are rounded and add up to the 82% for natural gas water heating referenced on page 13 of the 2022 REUS report.

h) Please see response at Exhibit I.1.10-GEC-7, Attachment 5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 3, Page 3

Preamble:

"in November 2020, Enbridge announced corporate ESG targets, which included targets related to reducing GHG emissions from operations. This includes achieving net-zero emissions by 2050 and an interim target of a 35% reduction in GHG emission intensity by 2030 relative to a 2018 base year."

Question(s):

a) Do Enbridge's GHG emissions reductions targets include: (i) direct emissions, (ii) indirect emissions, and (iii) customer emissions? Please explain.

b) Please provide a table showing the Enbridge's GHG emissions from 2018 (historical) through to 2030 (targeted).

c) How many gas-fired compressors does Enbridge own in Ontario?

d) Approximately how many gas-fired compressors will Enbridge replace between now and 2028? Of those, approximately how many will be replaced with an electric compressor versus a gas compressor?

e) Please provide complete the following table:

Activities to Achieve 35% GHG Reduction by 2030			
Activity	GHG reduction (tCO2e)	Forecast net incremental cost	Start and end date
Activity 1			
…			
Activity n			
Total of activities			
Total GHG reductions needed to meet 35% goal			

Response:

a) Please see Exhibit 1, Tab 10, Schedule 3, page 3, paragraph 8. Enbridge's corporate ESG targets are focused on scope 1 (direct GHG emissions) and scope 2 (electricity indirect GHG emissions) emissions. To date, other indirect GHG emissions, including customer emissions are not included in Enbridge's corporate ESG targets.

b) Please see Attachment 1, which provides Enbridge Gas's historical and forecasted emissions through 2030.

c) Please see Exhibit 2, Tab 6, Schedule 2, Page 179 of 288, Section 5.3.3 Storage and Transmission Asset Inventory, Table 5.3.3-1, which indicates a total of 53 gas-fired compressors in Ontario (14 in EGD rate zone, 39 in Union rate zones)

d) Enbridge Gas expects to replace nine compressors between now and 2028.

Seven of the nine compressors expected to be replaced are compressors at the Corunna Compressor Station and will be replaced by the Dawn to Corunna Pipeline project. Enbridge will not be replacing any of these seven existing compressors with electric compressors per the Dawn to Corunna Replacement Project Decision[1], which states

> "While electric compression may hold promise in future applications, the OEB finds that the orderly removal of the Corunna Compressor Station compressors in question and replacing the compression with existing capacity at Dawn to be the most cost effective approach to avoid potential reliability issues under these circumstances".

Two additional compressors have been identified for Life Cycle Replacement and electric compressors will be reviewed in the alternatives analysis giving due consideration to electrical grid reliability considerations and associated requirements and cost for gas fired standby compression:

i. Please see, Exhibit 2, Tab 6, Schedule 2, page 189 of 288, in Section 5.3.5.4.1 Compression Modernization, Waubuno Compression Life Cycle, and Exhibit 2, Tab 6, Schedule 2, Appendix A, page 8 of 59, Waubuno Compression Life Cycle

ii. Please see Exhibit 2, Tab 6, Schedule 2, page 189 of 288, in Section 5.3.5.4.1 Compression Modernization, Dawn C Compression Life Cycle, and Exhibit 2, Tab 6, Schedule 2, Appendix A, page 4 of 59, Dawn C Compression Life Cycle.

[1] EB-2022-0086, Decision and Order, November 3, 2022.

e) The interim target of a 35% reduction in GHG emission intensity by 2030 relative to a 2018 baseline is an Enbridge Inc. target. Please see Exhibit 1, Tab 10, Schedule 8, Table 1 for a list of Scope 1 and 2 emissions reduction opportunities already being undertaken as part of Enbridge Gas's Scope 1 and 2 emissions reduction plan to support the achievement of Enbridge Inc.'s ESG goals. There are no incremental costs to achieve these GHG reductions. Please see Exhibit 1, Tab 10, Schedule 8, Table 2 for a list of potential emission reduction opportunities which have undergone an initial economic analysis to determine estimated emissions reductions and net present value. Please note Enbridge Gas has identified an error in Table 1 of Exhibit 1, Tab 10, Schedule 8. The Forecasted Project Emissions Reductions for the Direct Inspection and Maintenance Program/Leak Detection and Repair (LDAR) Project should be 8,200 tCO2e, not 118,200 tCO2e.

Enbridge Gas Emissions Outlook

Line No.	Particulars	2018 Act	2019 Act	2020 Act	2021 Act	2022 Est	2023 F	2024 F	2025 F	2026 F	2027 F	2028 F	2029 F	2030 F
1	Emissions (tCO2e)	871,154	957,772	832,646	889,680	917,243	879,925	879,956	876,760	879,009	879,922	880,611	881,137	878,121

Note: 2022 audited emissions are not yet available

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, Page 17

Preamble:

"There is potential that climate change legislation, such as municipal or provincial plans to phase out the use of natural gas, could have a life-shortening effect on Enbridge Gas's system. However, there is also the possibility that service lives could be lengthened or maintained if low-carbon fuels, such as hydrogen and **RNG**, are determined to be viable sustainable alternatives to natural gas."

Question(s):

a) Please file a copy of all studies estimating the RNG potential in Ontario that Enbridge is aware of.

b) Please summarize the conclusions of RNG potential studies referred to in (a) regarding Ontario's RNG potential in the following table:

Ontario's RNG Potential (m3) – Comparison of Report Conclusions					
Feedstock	**Report 1 (potential year)[1]**	**Report 3 (potential year)**	**Report 3 (potential year)**	**…**	**Report n (potential year)**

c) Please file a copy of all studies estimating the RNG cost that would be applicable to Ontario that Enbridge is aware of.

d) Please summarize the conclusions of RNG potential studies referred to in (c) regarding Ontario's RNG potential in the following table:

[1] i.e. the year in which the stated potential is described in the report as being available.

RNG Cost in Ontario ($/m3) – Comparison of Report Conclusions					
Feedstock	**Report 1 (year)**[2]	**Report 3 (year)**	**Report 3 (year)**	**…**	**Report n (year)**
Feedstock 1					
…					
Feedstock n					
Weighted average					

Response:

a-b) Enbridge Gas is aware of three studies outlining supply potential for RNG in Ontario. Providing a comparison of supply potential by feedstock type and year is not feasible within the response timeframe; however, Enbridge Gas has provided references for each study in the list below. Enbridge Gas is also providing references to RNG potential studies carried out in other jurisdictions.

1. *RNG Potential Studies with Ontario Estimates*

    i. Renewable Natural Gas (Biomethane) Feedstock Potential in Canada: Torchlight Bioresources.[3] (see Figure 31)

    ii. Potential Production of Renewable Natural Gas from Ontario Wastes[4]

    iii. Benefits to the Economy, Environment and Energy (Canadian Biogas Association study as referenced in the Torchlight study)[5]

2. *RNG Potential Studies from Other Jurisdictions*

    i. Renewable Sources of Natural Gas: Supply and Emissions Reductions Assessment: American Gas Foundations[6] (see Figures 1 and 2)

[2] i.e. The year that the cost estimate relates to if it is not a current-year estimate.
[3] Renewable Natural Gas (Biomethane) Feedstock Potential in Canada, 2020, p.56, https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf
[4] EB-20211-0242, Exhibit B, Tab 1, Appendix 1, p.vi.
[5] Canadian Biogas Study: Benefits to the Economy, Environment and Energy, December 2013, https://www.build-a-biogas-plant.com/PDF/Canadian_Biogas_Study_Technical_Document_Dec_2013.pdf
[6] Renewable Sources of Natura Gas: Supply and Emissions Reduction Assessment, December 2019, p.3, https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf

ii. Potential Production of Methane from Canadian Wastes[7]

iii. Resource Supply Potential for Renewable Natural Gas in BC[8]

iv. Renewable natural gas (RNG) production: Key driver in the energy transition and economic development for Quebec regions[9]

c-d) Enbridge Gas is not aware of any studies specific to RNG costs, although production costs are available in the studies provided at part a). The cost of RNG supply for Ontario would depend on the quantity and price of supply purchased and cannot be estimated by Enbridge Gas.

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[7] Abboud S, Aschim K, Bagdan B, Sarkar P, Yuan H, Scorfield B, Felske C, Rahbar S, Marmen L, September 2010. Potential production of methane from Canadian wastes. Alberta Research Council and Canadian Gas Association.

[8] Resource supply potential for renewable natural gas in B.C., March 2017, https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf

[9] Renewable natural gas (RNG) production: Key driver in the energy transition and economic development for Quebec regions, https://mma.prnewswire.com/media/818573/_nergir_Renewable_natural_gas__Study_confirms_economic_potential.pdf?p=pdf

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, p. 14

Preamble:

"41. Regardless of the pathway chosen to achieve net-zero, the study found that energy efficiency, RNG, hydrogen and natural gas with CCUS are required, and net-zero cannot be achieved without these actions."

Question(s):

These questions are for Guidehouse:

a) Does the Guidehouse report study find that CCUS is required for Ontario to reach net-zero by 2050? If yes, please justify that conclusion and explain how it was reached in light of the fact that Guidehouse did not study a scenario that excludes CCUS.

b) Does the Guidehouse report find that significant use of RNG and hydrogen for residential heating is required for Ontario to reach net-zero by 2050? If yes, please justify that conclusion and explain how it was reached in light of the fact that Guidehouse did not study a scenario that is specific to this.

c) Does the Guidehouse report find that transportation of RNG and hydrogen through major pipelines required for Ontario to reach net-zero by 2050 (versus on-site electrolysis/storage or local pipelines)? If yes, please justify that conclusion and explain how it was reached in light of the fact that Guidehouse did not explicitly study this.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a-c) These questions pertain to the scenarios that were defined and explored in the *Pathways to Net Zero Emissions for Ontario* Study. The questions ask whether the technologies of CCUS, RNG and hydrogen heating, and RNG and hydrogen pipeline transportation are required for Ontario to reach net-zero by 2050. Further, the questions ask how Guidehouse could conclude that any of these technologies is required if Guidehouse did not test scenarios where these technologies were absent.

The P2NZ Study compared and contrasted two plausible scenarios under which Ontario can achieve net-zero emissions by 2050, given the policies and regulations that are in place or likely to emerge and given recent trends in technology development and adoption. Guidehouse judged it plausible that, in 2050, Ontario's heavy transportation and industrial sectors will still use some carbon-based fuels and that some building owners in Ontario will want to maintain fuel-fired heating systems. The *Pathways* analysis answered the questions, "What would need to happen for scenarios with these characteristics to occur? And what would it cost?" The *Pathways* study shows that, for the two scenarios examined (i.e., the Diversified scenario and the Electrification scenario), the least-cost method of supplying future energy demand involves the use of CCUS, RNG, and hydrogen transmission technologies.

The P2NZ Study does not find that CCUS, RNG and hydrogen heating, and RNG and hydrogen pipeline transportation are required for Ontario to reach net-zero by 2050 in *every conceivable scenario*. There may exist scenarios outside the scope of the P2NZ Study that achieve net-zero emissions in 2050 without the use of CCS, RNG, and hydrogen technologies. However, the purpose of the *Pathways* analysis was not to analyze every potential combination of technologies that could yield net-zero emissions by 2050.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1, p. 21

Preamble:

Exhibit 13 – Emission Factors

Fuel	Emission Factor (gramsCO2e/m3)	Notes/Assumptions
Natural Gas	1,899	• Calculated using a 100-year AR4 GWP values of 25 and 298 for CH4 and NO2 respectively.[8]
Natural Gas with Carbon Capture	389	• PG Analysis, using the 2020 NIR emission factors for CH4 and NO2 and assuming an 80% capture rate of CO2.
Renewable Natural Gas	11	• Enbridge Gas analysis, using the 2020 NIR emissions factors for CH4 and NO2 and assuming 100% of CO2 is biogenic.
Hydrogen	0	• Hydrogen does not produce combustion emissions.

Question(s):

a) Please provide the basis for the 80% capture rate for CCS. Please provide any underlying studies or reports.

b) Please explain the emissions factor for RNG. What portion of those emissions are fugitive emissions.

Response:

The following response was provided by Posterity Group:

a) The 80% capture rate was conservatively assumed based on literature research:

- At an industry sector level, CCS capture efficiency of 90% is commonly used in literature and feasibility studies regardless of technology type, location and fuel type.[1, 2]
- Sector specific references were also provided by Enbridge to further inform the assumption[3, 4, 5, 6, 7].
- Capture efficiency refers to the efficiency of the CCS 'unit' itself and does not represent the percentage of emissions captured via CCS vs. total facility emissions.

b) The Government of Canada's 2020 National Inventory Report (1990-2018)[8] provides end-use combustion emission factors for CH4 (0.037 g/m3) and N2O (0.035 g/m3). Because we are assuming 100% of CO2 is biogenic, only CH4 and N2O are contributing to GHG emissions. The same report references IPCC assumptions for CH4 and N2O global warming potentials (100-year AR4 GWP values of 25 and 298 for CH4 and N2O respectively). To calculate the total end-use combustion emission factor for RNG, we calculated gramsCO2e/m3 for CH4 and N2O:

- CH4 (gCO2e/m3) = 0.037 gCH4/m3 x 25 GWP = 0.925 gCO2e/m3
- N2O (gCO2e/m3) = 0.035 gN20/m3 x 298 GWP = 10.43 gCO2e/m3
- Total = 11.355 gCO2e/m3

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[1] Brandl, Patrick et al. "Beyond 90% capture: possible, but at what cost?" International Journal of Greenhouse Gas Control 105, Feb. 2021. [Online] Available: doi:10.1016/j.ijggc.2020.103239. [Last Accessed February, 2023].
[2] IEAGHG, "Towards Zero Emissions CCS from Power Stations using Higher Capture Rates or Biomass", 2019/02,March,2019.[Online]. Available at: http://documents.ieaghg.org/index.php/s/CLIZIvBI6OdMFnf/download [Last Accessed February, 2023].
[3] Cement: Barker, D.J., 2009. "CO2 Capture in the Cement Industry", Energy Procedia 1 (2009) 87-64, Available at www.sciencedirect.com [Last Accessed February, 2023]; Hills, T., 2015. "Carbon Capture in the Cement Industry: Technologies, Progress, and Retrofitting", Environmental Science & Technology, Available at pubs.acs.org/doi/pdf/10.1021/acs.est.5b03508 [Last Accessed February, 2023].
[4] Power segment: Smith, N., 2013. "Performance and Costs of CO2 Capture at Gas Fired Power Plants", Energy Procedia Volume 37, 2013, Pages 2443-2452, Available at https://doi.org/10.1016/j.egypro.2013.06.125 [Last Accessed February, 2023].
[5] Fabricated Metals Manufacturing: Perez-Fortes, M, 2014. "CO2 Capture and Utilization in Cement and Iron and Steel Industries", Energy Procedia Volume 63, 2014, Pages 6534-6543, Available at https://doi.org/10.1016/j.egypro.2014.11.689 [Last Accessed February, 2023]; Grantham Institute, 2014. "A Systematic Review of Current Technology and Cost for Industrial Carbon Capture". Available at https://www.imperial.ac.uk/media/imperial-college/grantham-institute/public/publications/institute-reports-and-analytical-notes/A-Systematic-Review-of-Industrial-CCS----GR7.pdf [Last Accessed February, 2023].
[6] Chemicals Manufacturing: Collodi, G. 2017. "Techno-economic Evaluation of Deploying CCS in SMR Based Merchant H2 Production with NG as Feedstock and Fuel", Energy Procedia Volume 114, July 2017, Pages 2690-2712. Available at https://doi.org/10.1016/j.egypro.2017.03.1533 [Last Accessed February, 2023].
[7] Petroleum Manufacturing: Grantham Institute, 2014. "A Systematic Review of Current Technology and Cost for Industrial Carbon Capture". Available at https://www.imperial.ac.uk/media/imperial-college/grantham-institute/public/publications/institute-reports-and-analytical-notes/A-Systematic-Review-of-Industrial-CCS----GR7.pdf [Last Accessed February, 2023].
[8] Government of Canada, "National Inventory Report (1990-2018)", 2020, Table A6.1-1, and A6.1-2.

Because our analysis reported end-use combustion emissions (not lifecycle emissions), the RNG factor does not include fugitive emissions

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1, p. 29

Preamble:

Critical Driver	Setting that deviates the most from the Reference Case assumption	Impact on Annual Volume by 2038	Impact on Peak	Impact on GHG Emissions by 2038
Carbon price	Max: $282/tonne.	22% decline	22% decline in hourly and daily peak	22% decline
Natural Gas Price	Max: 400% higher than current natural gas prices.	30% decline	~27% decline in hourly and daily peak	30% decline

Question(s):

a) Are the above two drivers considered to be additive? For instance, if both occur, would annual demand decline by 52%?

b) Please provide all calculations and assumptions underlying the assumption of a 30% decline in annual demand resulting from a 400% increase in gas prices. What does this amount to in terms of the differential between the price of home heating by gas versus electric heat pumps (lifetime $ difference and % difference)? At the time of the report, what was considered the “baseline” current price ($/m^3)?

Response:

The following response was provided by Posterity Group:

a) Yes, the two drivers are considered to be additive. Yes, we would expect a decline of 52%.

b)

i. *Please provide all calculations and assumptions underlying the assumption of a 30% decline in annual demand resulting from a 400% increase in gas prices.*

First, as a point of clarification, the gas commodity price was increased to 400% of the reference value (four times as high), rather than applying a 400% increase (five times as high). The table in the report did not make this clear.

The calculation of price-driven demand decline is different for each sector. In the residential sector, the calculations proceed as follows:

- Reference gas price in 2038 (in ¢/m^3) is estimated to be 15.90 for commodity, 13.37 for carbon, and 28.68 for other charges, for a total of 57.96 ¢/m^3.
- Multiplying the gas price by four results in 63.61 for commodity, 13.37 for carbon, and 28.68 for other charges, for a total of 105.67 ¢/m^3.
- This represents an increase of 82%, but PG uses a mid-point elasticity calculation, as explained in Section 3.1.2 of the report (please see Exhibit 1, Tab 10, Schedule 5, Attachment 1, pages 19-20). The percentage increase is therefore calculated relative to the average of the reference price and the new price. (105.67 – 57.96) / (Average (57.96, 105.67) – 1 = 58%
- Using a long-term elasticity of 0.38, the instantaneous response to this price increase would be -22%. To use the midpoint elasticity approach, PG applies an adjustment to this number, using the equation shown in Section 3.1.2. The calculation is as follows: (22% - 2) / (-22% - 2) – 1 = -19.9%
- The residential sector accounts for approximately 40% of total load.

In the commercial sector, the calculations proceed as follows:

- Reference gas price in 2038 is estimated to be 15.90 for commodity, 13.37 for carbon, and 19.15 for other charges, for a total of 48.43 ¢/m^3.
- Multiplying the gas price by four results in 63.61 for commodity, 13.37 for carbon, and 19.15 for other charges, for a total of 96.14 ¢/m^3.
- This represents an increase of 99%. Using the same mid-point elasticity approach as above, the percentage increase is therefore calculated relative to the average of the reference price and the new price. (96.14 – 48.43) / (Average (48.43, 96.14) – 1 = 66%
- Using a long-term elasticity of 0.35, the instantaneous response to this price increase would be -23%. To use the midpoint elasticity approach, PG applies the same adjustment approach as above: (23% - 2) / (-23% - 2) – 1 = -20.7%

- The commercial sector accounts for approximately 19% of total load.

In the industrial sector, the calculations proceed as follows:

- Reference gas price in 2038 is estimated to be 15.90 for commodity, 4.03 for carbon, and 17.03 for other charges, for a total of 36.96 ¢/m^3.
- Multiplying the gas price by four results in 63.61 for commodity, 4.03 for carbon, and 17.03 for other charges, for a total of 84.67 ¢/m^3.
- This represents an increase of 129%. Using the same mid-point elasticity approach as above, the percentage increase is therefore calculated relative to the average of the reference price and the new price. (84.67 – 36.96) / (Average (36.96, 84.67) – 1 = 78%
- Using a long-term elasticity of 0.7, the instantaneous response to this price increase would be -55%. To use the midpoint elasticity approach, PG applies the same adjustment approach as above: (55% - 2) / (-55% - 2) – 1 = -43.1%
- The industrial sector accounts for approximately 41% of total load.

Weighting the reduction for each of the three sectors by their share of the overall load results in the following calculation: (20% x 40%) + (21% x 19%) + (43% x 41%) = 30%.

ii. *<u>What does this amount to in terms of the differential between the price of home heating by gas versus electric heat pumps (lifetime $ difference and % difference)?</u>*

Posterity Group did not conduct a comparison of the cost of different home heating methods as part of this study. The additional research, analysis, and modelling required to answer this question cannot be completed within the IR timeframe.

iii. *<u>At the time of the report, what was considered the “baseline” current price ($/m3)?</u>*

The baseline (commodity) gas price in the base year of the study (2019) was 11.75 ¢/m^3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1, p. 29

Question(s):

a) What would the impact be on annual and peak gas demand if, starting in 2022, the cost-effectiveness of fully electrified heating/cooling with a heat pump was $11,071 cheaper than traditional gas heating (gas furnace, gas water heater, and AC) over the 15-year equipment lifetime? Please assume that the cost-effectiveness differential increases as the carbon price increases according to announced federal prices. Please provide a response on a best efforts basis. In answering the question, Posterity Group need not agree with any of the premises.

Response:

a) The following response was provided by Posterity Group:

Responding to this question would require modeling a new Demand Side Management (DSM) measure not currently included in the Navigator model constructed for this project. There is insufficient time to make that alteration to the model within the IR timeframe.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1, p. 40

Preamble:

Exhibit 26 – Scenario Narratives

Scenario Title:	Reference Case	Steady Progress	Diversified Portfolio	Electricity Centric

Question(s):

a) For each scenario, please provide relative cost-effectiveness of residential space conditioning and cooling from a customer perspective as between (i) gas equipment and a traditional air conditioner, (ii) hybrid heating, and (iii) a house fully electrified with heat pumps (and not required to pay for gas distribution charges).

b) Please confirm that the relative cost-effectiveness of the above options will impact gas demand.

c) Page 40 states: “The ETSA project team built off the scenario narratives envisioned by Enbridge Gas prior to beginning the project to draft scenario narratives.” Please provide a copy of what Enbridge provided.

d) This question is for Enbridge: How did Enbridge develop the scenario narratives provided to Posterity Group? Please provide any reports or memos in relation the development of those narratives.

e) Please assess the relative probability of the future being more similar to the reference case, study progress, diversified portfolio, or electricity centric scenarios.

Response:

a-b) The following response was provided by Posterity Group:

The Navigator model can conduct cost-effectiveness tests on individual measures, but is not designed to produce the kind of cost-effectiveness calculation contemplated in this question. Also, developing costs estimates were not part of the study scope.

c) The following response was provided by Posterity Group:

Scenario narratives were developed via discussions with the Enbridge Gas team. Enbridge Gas did not provide a document describing what the organization envisioned.

d) As noted by Posterity in part c), scenario narratives were developed via discussions between Enbridge Gas and Posterity. Enbridge Gas and Posterity worked collaboratively and through an iterative process to develop the scenarios and critical driver settings. The process describing the development of scenario narratives and the final scenario narratives is provided in Exhibit 1, Tab 10, Schedule 5, Attachment 1, pages 39 to 41.

e) The following response was provided by Posterity Group:

We did not assign any probabilities to any of the scenarios. We view the multi-scenario modeling approach as a way to mitigate risk. We advise our utility clients to develop plans that are robust in the face of a range of plausible scenarios, particularly in cases where future policy, prices, and economic variables are uncertain.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1, 40

Preamble:

Exhibit 15 – Sensitivity of Annual Volumes, Peak and GHG Emissions by Critical Driver

Critical Driver	Setting that deviates the most from the Reference Case assumption	Impact on Annual Volume by 2038	Impact on Peak	Impact on GHG Emissions by 2038
Carbon price	Max: $282/tonne.	22% decline	22% decline in hourly and daily peak	22% decline
Natural Gas Price	Max: 400% higher than current natural gas prices.	30% decline	~27% decline in hourly and daily peak	30% decline
Non-Price Driven fuel-switching (gas to electricity)	Max: Beginning in 2025, no new gas connections, and space and water heating equipment at existing accounts must be replaced with electric alternatives at the equipment's natural end of life.	42% decline	Hourly peak: 50% decline Daily peak: 55% decline	42% decline

Question(s):

a) Please confirm whether any of the scenarios studied include any of the three drivers noted above. If not, why not. Please explain in detail.

b) What is the likelihood that one of the three "settings" above would come to pass? Please provide the likelihood for each individually, and the likelihood that any one of them would come to pass. Please justify the answer with specific details.

Response:

The following response was provided by Posterity Group:

a) Exhibit 27 in Section 6 of the report provides the details of the settings for each of the critical drivers in each scenario (please see Exhibit 1, Tab 10, Schedule 5, Attachment 1, pages 42-43). None of the exact settings in the preamble to this IR were used in the modeled scenarios. The scenario settings provided in Exhibit 27 were based on the scenario narratives developed by the ETSA project team and finalized with input from internal and external stakeholders, as described in Section 6.2 of the report.

b) We have not attempted to assign probabilities to the likelihood that each setting would come to pass. We view the multi-scenario modeling approach as a way to mitigate risk. We advise our utility clients to develop plans that are robust in the face of a range of plausible scenarios, particularly in cases where future policy, prices, and economic variables are uncertain.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

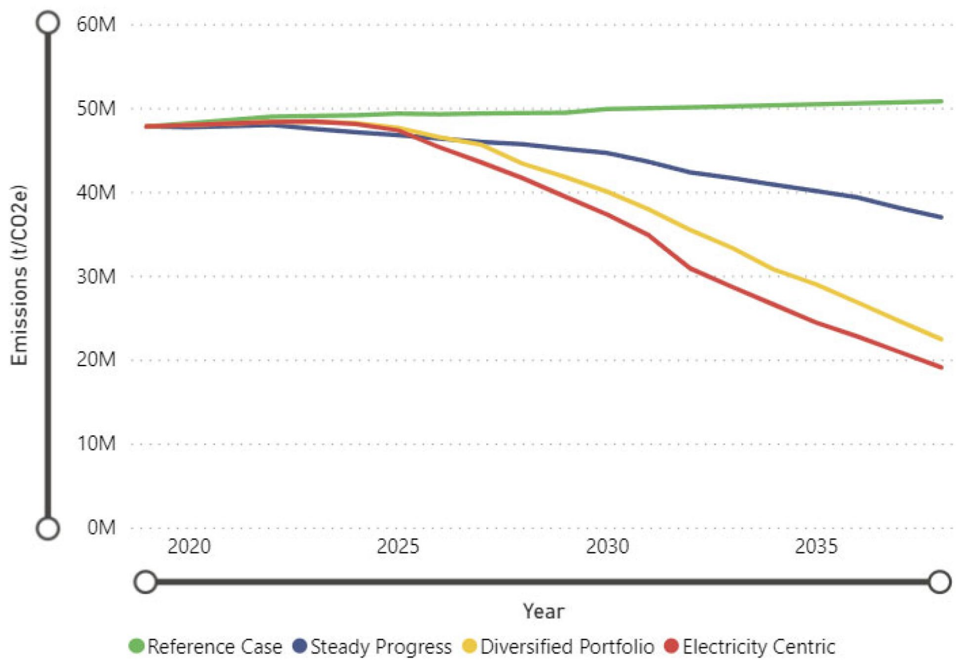
Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1, p. 79

Preamble:

Exhibit 71 – Scenarios Comparison: GHG Emissions



Question(s):

a) Please reproduce the above figure including full lifecycle emissions, including upstream emissions (e.g. from fossil-fuel-based hydrogen, transmission methane leaks, etc.) and methane leaks from customer equipment. Please make and state your assumptions for those.

For upstream emissions from fossil-fuel-based hydrogen, please use the figures found in the following peer-reviewed report or justify a decision to use different figures: Robert W. Howarth and Mark Z. Jackson, "*How green is blue hydrogen?*" *Energy Science & Engineering*, 26 July 2021 (link).

For the emissions of unburned methane from customer equipment, please use the figures found in the following peer-reviewed report or justify a decision to use different figures: Zachary Merrin and Paul W. Francisco, *Unburned Methane Emissions from Residential Natural Gas Appliances* (link).

Response:

a) The following response was provided by Posterity Group:

Our analysis reported end-use combustion emissions (not lifecycle emissions). Undertaking new research, developing appropriate lifecycle emissions, and remodeling using lifecycle emissions cannot be completed within the IR timeframe.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1

Preamble:

- *Electricity Centric Scenario:* The fuel shares for residential and commercial space heating is 27% and 24% respectively by 2038 (approximately 800,000 customers). As the natural gas system is contracting, investment into adding new hydrogen loops (additional customers) is not made. Blend percent is increased from 2% to 10% in 2035 for customers on existing hydrogen loop (21,000 customers).

Exhibit 101 – Hydrogen Blend in the Steady Progress and All Electric Scenarios

	Steady Progress Scenario (# customers receiving 10% H2)	All Electric Scenario (#customers receiving 10% H2)
2035	200,000 customers	18,760 customers
2038	800,000 customers	20,770 customers

Question(s):

a) Why does Posterity Group assume that customers were use 10% hydrogen? Does Posterity believe this would be cheaper than customers converting to electric heating? If yes, why?

b) What is the “existing hydrogen loop” referred to above?

c) What are the RNG assumptions for the steady state and all electric scenarios?

Response:

The following response was provided by Posterity Group:

a) Posterity Group modeled the scenarios developed by the ETSA project team and finalized with input from the internal and external stakeholders. The inputs for the hydrogen critical driver included an assumption that blend percent could be increased to 10% in 2035. We did not conduct an analysis of which option would be less expensive for the customer

b) The existing hydrogen loop refers to the customers served by Phase 1 of Enbridge Gas's Low Carbon Energy Project.

c) As detailed in Exhibit 27 in Section 6 of the report (please see Exhibit 1, Tab 10, Schedule 5, Attachment 1, page 42), the Steady Progress scenario includes the following assumptions regarding RNG:

- Clean Fuel Regulation (CFR) directs RNG and H2 to transportation
- CFR provides modest incentive for CCS, RNG & H2
- H2 cost competitive with natural gas in 2035, RNG is cost competitive in 2030

The Electricity Centric scenario includes the following assumptions regarding RNG:

- CFR remains, like Steady Progress scenario
- H2 cost competitive with natural gas in 2035, RNG is cost competitive in 2030

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 1, p. 113

Question(s):

a) According to Posterity Group, what is the feasible RNG potential in Ontario (PJ/d)? Please justify the answer with reference to RNG potential studies. Please compare the answer to the RNG potential found by the OEB in its Marginal Abatement Cost Curve study.

b) Please reproduce the above, inserting amounts in terms of PJ/d.

c) If RNG potential in Ontario is 40 PJ/d, how would that impact the peak gas volume results of the various scenarios.

Response:

The following response was provided by Posterity Group:

a-b) Posterity Group did not conduct an analysis of the feasible RNG potential in Ontario.

Within the IR timeframe there is insufficient time for Posterity Group to undertake an analysis of the feasible RNG potential in Ontario and compare these amounts to the OEB's Marginal Abatement Cost Curve study.

We interpret the intent of ED-23 part b) is to request that we reproduce the first row of Exhibit 102 on Exhibit 1, Tab 10, Schedule 5, Attachment 1, page 113 in terms of PJs of RNG. Below we present the original first-row and a new row added at the bottom showing annual PJs of RNG for the years 2025, 2030, 2035 and 2038. We are unable to comment on what this would look like in terms of daily or peak production capacity.

	2025	2030	2035	2038
RNG (% of total energy)	0.5% (starts)	5%	10%	13%
Annual RNG demand (PJ)	5	48	87	105

c) Since RNG is considered interchangeable with natural gas, with its comparable energy content and seasonal storage abilities, in our modelled scenarios we assume substitution of natural gas with RNG will not impact peak gaseous volume.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2

Question(s):

a) Please provide a list of the authors of the Guidehouse report and copies of their CVs.

b) Please provide a table showing the decarbonization pathways studies that the report authors have worked on, a description of their role(s) in said studies, and links to (or copies of) those studies.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Authors of the *Pathways to Net Zero Emissions for Ontario* Study include Nicola Charles, Decker Ringo, Alvaro Lara, Marissa Moultak, David Mavins, and Andrea Roszell. Decker Ringo and Andrea Rozsell's CVs are provided at Exhibit 1, Tab 1, Schedule 6, pages 77 to 83. Copies of the rest of the authors CVs are provided in Attachment 1.

b) Table 1 shows the decarbonization pathways studies that the report authors have worked on and a description of their role(s) in said studies. The table provides footnotes with links to publicly available studies.

Table 1

Contributing Authors & Prior Reports

Author	Prior Report (s)	Role
Nicola Charles	National Grid NY[1]	Lead model developer and analyst for multiple decarbonization pathways studies.
Decker Ringo	NFGDC[2], National Grid NY[1]	Led model development, supporting input data collection and forecasting, assessment of outputs, and reporting.
Alvaro Lara	Pan-EU[3], National Grid UK (publication pending), GRTGaz[4], Nordion[5]	Lead analyst and modelling advisor on a variety of decarbonization pathways projects.
Marissa Moultak	Pan-EU[2], National Grid UK (publication pending), GRTGaz[3], Nordion	Analyst and modeler on decarbonization projects, applying in depth energy system optimization modeling to help inform policy.
David Mavins		No prior pathways experience with Guidehouse.
Andrea Roszell	FortisBC Pathways[6]	Acted as project manager for the development of pathways to meet provincial GHG reduction targets.

[1] Guidehouse (2022). “National Grid New York Climate Leadership and Community Protection Act Study.” Available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FCE50650-4AF2-484A-9855-1271A55F0E91}

[2] Guidehouse (2021). “Meeting the Challenge: Scenarios for Decarbonizing New York’s Economy”. Available at https://guidehouse.com/-/media/www/site/insights/energy/2021/meeting-the-challengescenarios-for-decarbonizing-n.pdf

[3] Navigant (2019). “Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain”. Available at https://www.energynetworks.org/industry-hub/resource-library/pathways-to-net-zero-decarbonising-the-gas-networks-in-great-britain.pdf

[4] Guidehouse (2021). “Competitiveness of France: Role of hydrogen transport and storage infrastructure”. Available at https://www.storengy.com/sites/default/files/mediateque/pdf/2021-11/2021-11-25_H2%20in%20France_Concept%20Paper.pdf

[5] Guidehouse (2021). “The Role of Gas and Gas Infrastructure in Swedish Decarbonisation Pathways 2020-2045” Available at https://energiforsk.se/media/29966/the-role-of-gas-and-gas-infrastructure-in-swedish-decarbonisation-pathways-energiforskrapport-2021-788.pdf

[6] Guidehouse (2020). “Pathways for British Columbia to Achieve Its GHG Reduction Goals.” Available at: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf

Alvaro Lara

Managing Consultant

alara@guidehouse.com
Abu Dhabi, UAE
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Professional Summary

Alvaro Lara is a Managing Consultant in Guidehouse's Energy, Sustainability and Infrastructure practice with 7+ years of experience supporting electric and gas companies, government, and regulators across North America, Europe and the Middle East. His expertise includes electricity and gas integrated system modelling, energy system decarbonization pathways, hydrogen system planning, grid modernization and smart grid investment plans, rate-setting, regulation and policy. Most recently, Alvaro has supported electricity and gas utilities in Canada, the UK and the Nordics in the assessment of integrated electricity and hydrogen infrastructure planning.

Alvaro's experience also includes the electric mobility space, as an Operations Manager (Clean Air & Electrification) at Uber, where he led the implementation of Uber's Clean Air Plan strategy in London. Alvaro holds a BEng. in Mechanical Engineering from the University of Toronto (Canada) and an MSc in Climate Change, Management and Finance at Imperial College Business School (UK).

Areas of Expertise

- **Electricity and Gas System Modelling and Decarbonization Pathways:** Developed decarbonization pathways and high-level infrastructure plans for gas transmission and distribution infrastructure companies supporting their transition from natural gas to low-carbon and renewable gas (biomethane, hydrogen).
- **Business Cases for Grid Modernization & Smart Grid Investments:** Conducted multiple detailed costs-benefit analyses (CBA) of grid modernization investments, electric vehicles, microgrids, and other emerging technologies for distribution utilities, governments, and project developers.
- **Electricity Rate Setting Regulation and Policy:** Support energy regulator in developing forecast of wholesale market prices and regulated electricity rates. Assess costs and risks associated with a policy alternatives based on detail review of supply and demand conditions and conduct statistical and probabilistic analyses to support strategic advice.

Professional Experience

Energy System Decarbonization Pathways

- **UK Electricity and Gas Transmission Outlooks to 2050, Modeling Lead, National Grid GB. (2022).** Assessment of electricity and gas (natural gas and hydrogen) transmission infrastructure pathways from 2025 to 2050. Analysis models an integrated electricity, hydrogen and methane system covering a geographic scope made up of eleven subregions with GB, seven offshore electricity / hydrogen production nodes and three neighboring regions (Ireland, Western Europe and Northern Europe). Analysis will support National Grid's vision of evolving its currently siloed electricity and gas system planning towards an integrate "whole system" planning approach.

Guidehouse

Alvaro Lara

Managing Consultant

- **Decarbonization Pathways for Ontario's Energy System, Modelling Advisor, Enbridge Gas Inc. (2021-22).** Assessment of various decarbonization pathways for Ontario's electricity and gas systems towards 2050. Analysis aimed at identifying a least-cost, net-zero energy system, as well as identifying required investments in electricity and gas supply and infrastructure associated with those visions of Ontario's energy systems. Final report will support Enbridge's strategic positioning of the role played by low carbon and renewable gas in achieving net-zero emission in Ontario.
- **Gas Decarbonisation Pathways, Project Manager, Northern Ireland Gas TSOs & DNOs (2021).** Development of gas decarbonisation pathway for gas transmission and distribution companies in Northern Ireland (NI). Analysis serves a foundation for NI gas networks' decarbonisation plans and investments over their next regulatory period (2022-2026), as well as feeding into the NI Gov's energy strategy, part of the UK's Net Zero 2050 strategy.
- **Gas Decarbonisation Infrastructure Pathways, Lead Analyst, Nordic Gas Infrastructure Companies (Nordion Energi & Gas DSOs) (2021).** Lead analyst developing decarbonisation pathways for the Swedish energy system to understand the buildout of electricity, hydrogen and methane supply capacity, and associated transmission infrastructure within Swedish regions and with neighboring regions. Gas infrastructure and investment plans developed based on two main demand scenario and various sensitivities.
- **Decarbonisation of GB's Gas Networks, Modelling Lead, Energy Networks Association (2019).** Lead modelling of 2050 net-zero vision for GB's energy system, focusing on decarbonisation pathways from 2020 to 2050 for the gas networks, and the development of hydrogen and biomethane gas infrastructure and the electrification of heat.

Business Cases for Grid Modernization & Smart Grid Investments

- **Smart Grid Strategy and Roadmap, Workstream Lead, Middle East Utility (DEWA) (2018).** Lead development of cost-benefit analysis of smart grid portfolio including investments in Advanced Metering Infrastructure (AMI), Distribution Automation, Transmission Automation, Asset Management, Customer Engagement, among other areas. Supported development of AMI strategy roadmap for future functionalities; AMI customer-fingerprinting, energy services cross-selling, and external-data insights.
- **Customer-DER Distributed-Intelligence Analysis, Economic Analysis Lead, US Utility (Duke Energy) (2017).** Lead economic assessment of customer-sited distributed energy resources (DER) – predominantly distributed-solar PV and storage – on US Midwest GT&D utility's network. Analysis identified prioritization schedule of utility investment and network feeders optimal for customer DER adoption. Duke Energy – Cost-benefit analysis of a collection of distributed intelligence technologies focused on the transformation of the distribution grid driven by the adoption DER resources (solar PV and storage). Analysis based on the characteristics of a selection of representative feeders, low/high DER forecasts, microgrid forecasts, declining technology costs, reliability improvements, and improved utility O&M.

Guidehouse

Alvaro Lara

Managing Consultant

- **Distribution-Network Efficiency Potential Assessment, Workstream Lead, Government (Ontario Ministry of Energy) (2017).** Lead cost-benefit analysis of Volt/VAR optimization (VVO) investments in Ontario's distribution networks. Developed CBA framework for analysis and implemented feeder-level analysis using 15 prototypical feeders. Results were extrapolated to Ontario's 10,000 feeders. Analysis led to VVO becoming eligible for regulator funding and inclusion into utility DSM strategies
- **Customer Time Varying Rates & AMI Grid Modernisation Plan, Lead Analyst, US Utility (Eversource Energy) (2015)**. Lead cost-benefit analysis of grid modernization in support of Eversource's Short Term Investment Plan (STIP) and regulatory filing requirement in Massachusetts. Grid Modernization plan included assessment of new opt-in/opt-out customer tariff rates, and investments in overhead and underground distribution automation and fault-detection. Results enabled utility to file grid modernization investment plan and to obtain regulatory approval.

Electricity Rate Setting Regulation and Policy

- **Customer Tariff Rate Setting Process, Project Manager, Canadian Energy Regulator (2015/17)**. Managed semi-annual assessment of Ontario's wholesale electricity market and lead update of regulated customer electricity rates. Developed alternative customer pricing structures for assessment and implementation by energy regulator. Ongoing support to Ontario's utility regulator in the development of a market price forecast for Ontario's wholesale electricity market and forecasting regulated electricity rates for electricity customers in the province.
- **Rate Impact Assessment from Customer Tariff Policy Scenarios, Lead Analyst Lead, Government (Ontario Ministry of Energy) (2016).** Analyzed the financial and electricity system impacts of incremental load additions on ratepayers, and current supply-demand conditions. Analysis lead to policy changes and development of expansion of rate tariff structures to large-load customers. Evaluated scenarios through risk assessment modelling, and develop recommendations based on workshops with the IESO, OEB, and large consumer stakeholder groups.
- **Distributed Generation Financial Impact, Lead Analyst, Toronto Hydro (2016)**. Develop financial model to quantify the historical financial impact of distributed generation (DG) on a Toronto Hydro's business operations. Forecasted future financial impact and developed recommendations to mitigate impact, recover revenue requirement, and promote DG growth

Work History

- Managing Consultant, Guidehouse
- Operations Manager, Uber
- Consultant - Senior Consultant, Navigant

Education

- MSc. Climate Change, Management & Finance, Imperial College Business School (UK)
- BEng. Mechanical Engineering, University of Toronto (Canada)

Guidehouse

David Mavins

Consultant

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Professional Summary

David is a Consultant in the Energy, Sustainability & Infrastructure segment at Guidehouse's Toronto office. David is Interested mainly in projects involving utility strategy with respect to new technology and services, His broad knowledge and skills make him effective at understanding links between multiple disciplines.

David worked on a multidisciplinary team at a major Ontario utility, focusing on strategy, enterprise risk management, performance management, corporate disaster preparedness, and stakeholder management. His experience has given him a comprehensive understanding of how utilities think and act.

Areas of Expertise

- **Distributed Energy Resources:** Supports development of strategies for utilities to implement distributed energy resources
- **Electric Vehicles:** Supports development of strategies to increase adoption of electric vehicles
- **Energy Efficiency Program Assessment:** Analyzes data from past energy efficiency programs to determine efficacy of data collection and program execution
- **Energy Efficiency Regulations:** Models the hypothetical future effects of proposed Minimum Energy Performance Standards to determine the potential energy savings and impact on the market
- **Evaluation, Measurement, and Verification:** Evaluates data collected through energy efficiency programs to confirm whether reported savings are accurate

Professional Experience

Distributed Energy Resources

- **Alectra, Unregulated Business Strategy.** Assisted in the development of Alectra's unregulated business strategy by determining most promising potential product and service offerings.

Guidehouse

- **Canadian Electricity Association, Regulatory Waste Study.** Analyzed regulatory waste across the Canadian electricity sector and compared with innovative regulation in other jurisdictions. Provided recommendations on how to modify regulations to encourage deployment of non-traditional distribution infrastructure and projects.

Electric Vehicles

- **BC Hydro, Electric Vehicle Rate Design.** Analyzed rate structures and regulatory proceedings for electric vehicle charging from various utilities and jurisdictions to provide recommendations for BC Hydro's electric vehicle charging rate design.
- **Exelon, Fleet Electrification.** Built database of all known present and future electric vehicle offerings in the US to assist in development of a client's fleet electrification strategy.

Energy Efficiency Program Assessment

- **Energy Efficiency Alberta, Past Program Analysis.** Analyzed and aggregated historic data into dashboards to help an energy efficiency agency better understand its customer base and identify gaps in data collection.

Energy Efficiency Regulations

- **Natural Resources Canada, EnerGuide Labelling Study.** Collected and analyzed data on energy efficiency labelling compliance for large appliances at a variety of retailers across Canada.
- **Natural Resources Canada, Market Studies.** Characterized the current market and forecasted the future market and stock for refrigerators and freezers in Canada. Reviewed regulatory and voluntary requirements related to energy efficiency. Produced a report to help the federal government determine the efficacy, reasonableness, and potential impacts of proposed energy efficiency standards. Contributed to similar reports on pool pumps and air compressors.

Evaluation, Measurement, and Verification

- **Energy Efficiency Alberta, Evaluation, Measurement, and Verification.** Assisted in the savings validation of several residential and commercial energy efficiency programs.

Work History

- Consultant, Guidehouse
- Student, Strategy & Enterprise Risk Management, Toronto Hydro

Education

- BAS, Engineering Chemistry, Queen's University

Guidehouse

Marissa Moultak
Senior Consultant

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Direct: +31 30 662 3007

Professional Summary

Marissa is a senior consultant in the energy, sustainability, and infrastructure practice. With more than four years of experience advising energy companies, governments, and corporations on various decarbonisation topics.

Specialised in energy system modelling, Marissa supports clients by leading model based analyses to provide data-driven recommendations on decarbonisation and renewable integration.

With a strong technical background in Chemical Engineering and a masters in Complex Systems Engineering and Management, Marissa addresses challenging technical questions to help drive the energy transition.

Areas of Expertise

- **Energy System Optimisation:** Performs in-depth integrated energy system optimisation modelling to help clients answer a wide variety of questions regarding the future decarbonised energy system**.**
- **Decarbonisation Pathways:** Advises companies and governments on decarbonisation strategies using energy system modeling.
- **Demand Forecasting:** Performs in-depth demand analyses to determine future hydrogen and electricity demand.

Professional Experience

Energy System Optimisation

- **Gas for Climate, Hydrogen Transmission Study.** Applied in-depth energy system optimisation modelling to determine the benefits of a Pan-European hydrogen transmission system. Contributed to a public report that provides data-driven insights into the benefits of a Pan-European hydrogen transmission system to help inform policy.
- **Eneco, Renewable Energy Investment Analysis.** Developed an energy system model paired with an investment model to help inform the client's future investments in renewable energy.

Decarbonisation Pathways

- **Mutal Energy, Northern Ireland Pathway to Net Zero.** Performed energy system optimisation modelling to help the clients explore decarbonisation pathways for low carbon and renewable gas supply and gas infrastructure. Conducted sensitivity analyses to help the clients understand the range of possible future outcomes and help inform their decarbonisation strategy.

Guidehouse

Marissa Moultak
Senior Consultant

Demand Forecasting

- **European Hydrogen Backbone, Hydrogen Supply and Demand Study**. Developed a model to forecast hydrogen demand across the European market. Contributed to a public study and webinar that analysed the future demand, supply, and transport of hydrogen to help inform the clients, industry, and policymakers about the future hydrogen market in Europe.

Work History

- Senior Consultant, Guidehouse
- Consultant, Guidehouse
- Fundamental Analysis Graduate Thesis Intern, Eneco
- Acquisition Committee & Project Team Member, IRPdelft & LM Wind Power
- Electric Vehicle Fellow, International Council on Clean Transportation (ICCT)
- Sustainable Mobility & Powertrain Engineering Intern, BMW Group Technology Office

Education

- Master of Science, Complex Systems Engineering & Management (Energy track), Delft University of Technology
- Bachelor of Science, Chemical Engineering, University of California, Berkeley
- Minor, Energy and Resources, University of California, Berkeley

Thought Leadership

European Hydrogen Backbone (2021, June). Analysing future demand, supply, and transport of hydrogen. https://gasforclimate2050.eu/publications/

Moultak, M. (2021, June 28). Analyzing investments in the power system using optimization modeling. https://repository.tudelft.nl/islandora/object/uuid%3A7d2f5c02-e1fb-4bb5-ad72-a4e107796506

Moultak, M., Hall, D., & Lutsey, N. (2017, September 26). Transitioning to zero-emission heavy-duty freight vechicles. The International Council on Clean Transportation (ICCT). https://theicct.org/publications/transitioning-zero-emission-heavy-duty-freight-vehicles

Hall, D., **Moultak, M.**, & Lustey, N. (2017, March 3). Electric vehicle capitals of the world: Demonstrating the path to electric drive. The International Council on Clean Transportation (ICCT). https://theicct.org/publications/EV-capitals-of-the-world

Guidehouse

Nicola Charles

Senior Consultant

nicola.charles@guidehouse.com
Toronto, Canada
Direct: 416.777.2461

Professional Summary

Nicola is a Senior Consultant in the Data Analytics sub-practice of Guidehouse's Toronto Energy practice. Nicola provides modeling expertise and applies a range of cutting-edge techniques—including optimization, regression analyses, machine learning, geographic information systems (GIS), and econometrics—to challenges in the energy industry.

As the industry looks to meet emerging carbon emissions targets, Nicola helps chart the pathways there. Specializing in economy-wide decarbonization, she performs in-depth linear optimization techniques to determine how energy systems need to evolve to meet the demand of electrification at the least cost to society.

Through her evaluation of energy efficiency programs and modelling of achievable potential, Nicola supports the design of energy efficiency programs across North America. She has experience evaluating a variety of demand response programs including multi-family water heater programs, residential smart thermostat programs, and commercial and industrial direct load control programs. She completes this work through the advanced use of analytical tools such as Python and R and is well versed in handling large datasets through SQL.

Areas of Expertise

- **Low Carbon Pathways:** Advises clients on the cost-optimal pathways to achieve carbon emission reductions informed by in-depth optimization modeling around economy-wide decarbonization.
- **Econometric Impact Evaluation:** Performs detailed analysis of demand response and energy efficiency customer programs to determine robust impacts using statistical regression methods.
- **Energy Efficiency and Cost Effectiveness:** Uses a suite of analysis approaches including achievable potential modeling to inform energy efficiency program design.

Professional Experience

Low Carbon Pathways

- **Enbridge, Ontario Decarbonization Pathways Study.** Nicola led the modeling efforts to evaluate two different pathways to achieve net-zero carbon emissions by 2050 and their associated impacts for Ontario in terms of overall feasibility, energy system capacity, system reliability, GHG emission reductions, and cost.

  Using an integrated energy system model adapted to the characteristics of Ontario's gas and electricity networks, Guidehouse identified future investments in electricity, hydrogen, and methane supply and infrastructure needed for Ontario's energy system to support economy-wide decarbonization.

Nicola Charles

Senior Consultant

Econometric Impact Evaluation

- **Duke Energy, EnergyWise Demand Response Evaluation.** Nicola is the impact lead for the evaluation of Duke Energy Florida's EnergyWise Home residential demand response program. In the 2019 analysis, she estimated the ex post and ex ante impacts of a subset of participants to examine the discrepancies of utilizing whole-home Advanced Metering Infrastructure (AMI) data versus installed A/C logger data. Her research showed that there is no statistically significant difference between the two methods, which allowed Duke Energy to leverage their investments in AMI and forgo the more costly deployment of device loggers for future demand response evaluations.

- **EmPOWER, Smart Thermostat Evaluation.** Nicola was part of the core analysis team working to determine the energy savings resulting from smart thermostat installations across five different utilities in Maryland. With the efficient use of regression techniques applied to cloud-hosted data, the team was able to estimate the effects of thermostats on residential energy loads across the study period. The result of this study was a robust savings estimate to be used for program planning and design.

- **Newfoundland Power, Thermostat Evaluation.** Nicola led the evaluation of a thermostat rebate program in Newfoundland and Labrador. The result of this study was a locally appropriate and program specific energy savings rate for a program that has been in operation for over 10 years. Going forward, the utilities can use this value to evaluate further investments in thermostat energy efficiency in the province.

- **PGE, Demand Response Evaluation.** Nicola has led the analysis for the evaluation of various demand response customer programs and pilots run by PGE from 2018 through 2022. Through her evaluation of their medium and large commercial customer pilot, she was able to support the pilot's transition to full demand response program. In addition to this, Nicola evaluated the commercial smart thermostat pilot and helped establish key cost-effectiveness metrics for the pilot. She also evaluated their multi-family water heater demand response program and provided key insights from equipment telemetry data to more efficiently access devices.

Energy Efficiency and Cost Effectiveness

- **IESO and OEB, 2019 Achievable Potential Study.** Characterized over 250 residential and commercial energy efficiency and fuel switching measures at very detailed levels of granularity across the study's entire jurisdiction. Led model QC at the measure level for technical potential. Led modeling efforts for 2 achievable potential scenarios and developed multiple tools to tailor results to specific client needs. Assisted in model optimization updates and sensitivity analysis. The results of this study directly inform program design and planning in Ontario today.

Nicola Charles

Senior Consultant

- **IESO, Cost Effectiveness Tool.** Nicola created an efficient cost effectiveness tool in Python which simulates the energy benefits, GHG emissions, and total budget spend of energy efficiency measure inputs. This tool helps facilitate energy efficiency program design in Ontario.

- **Duke Energy, Multi-Family Energy Efficiency Program EM&V Services**. Nicola led the analysis for the lighting logger study of multi-family dwellings across various Duke Energy Carolinas jurisdictions to measure the typical operating hours for program LEDs. The lighting logger data was extrapolated to create accurate estimates of annual hours of use by space type and lamp type. These program-specific estimates are now used to support energy efficiency program design regarding LEDs.

- **Energy Efficiency Alberta, eTRM**. Helped create an adaptive electronic TRM. Scripted algorithms to create interactive tools for computing the technical potential of each energy efficiency measure tailored to user inputs and verified measure validity.

- **BrightWind, Predictive Analytics for Wind Energy**. Built a neural network pipeline in Python to predict the power output of every windfarm in Ireland using weather predictions. Expanded on this by developing empirical learning models based on Markovian probabilities to predict power output based on historical power data.

Work History

- Senior Consultant, Guidehouse
- Data Analytics Intern, BrightWind

Education

- Bachelor of Engineering, Applied Mathematics and Mechanical Engineering, Queen’s University

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

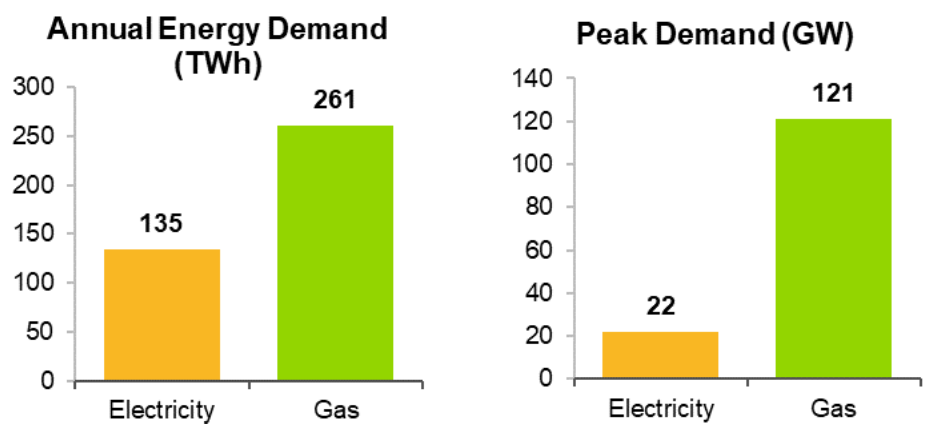
Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2

Preamble:

Figure 4. Comparison of Ontario's Electricity and Natural Gas Demand (2019)



Question(s):

a) Please provide an excel spreadsheet showing the total Ontario gas demand for each hour in 2019 and 2020. We wish to use the data to assess the "peakiness" of gas demand.

b) Please provide an excel spreadsheet showing the total Ontario electricity demand for each hour in 2019 and 2020. We wish to use the data to assess the "peakiness" of elect.

Note – We wish to use the above information to assess the "peakiness" of Ontario's gas demand and electricity demand; to compare the two; and assess the reports characterization of each.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Guidehouse declines to provide a response because the requested data was not used in the development of the Pathways to Net-Zero Emissions for Ontario (P2NZ) study. As a starting point, Guidehouse used annual and peak gas demand estimates from the ETSA study for the year 2020.

b) The electricity demand data for the starting decade of the study (2020) was sourced from the IESO for the calendar year 2019 to avoid any impacts due to the COVID-19 pandemic. The hourly demand profiles that Guidehouse referenced from 2019 are available from the IESO Data Directory.[1]

[1] IESO Data Directory. Available at: https://www.ieso.ca/en/Power-Data/Data-Directory#Ontario-and-Market-Demand

ENBRIDGE GAS INC.

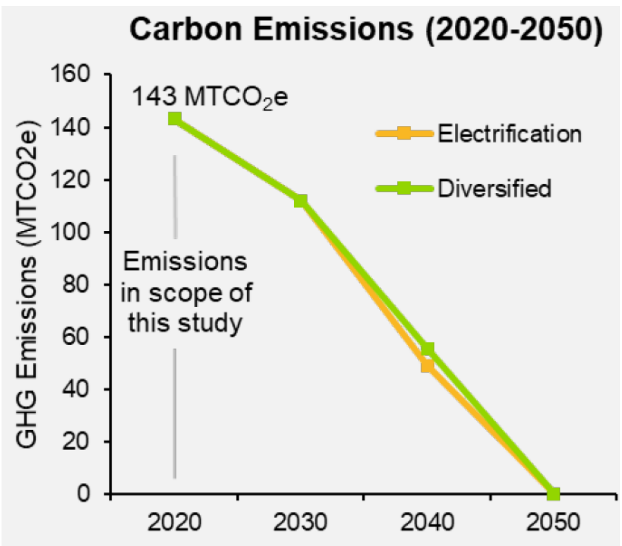
Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 3

Preamble:



Question(s):

a) Please provide an updated version of the above figure that accounts for the full lifecycle emissions associated with gaseous fuels (including as many of those listed in (b) as possible). Please provide all calculations and assumptions. Please make assumptions and state caveats as necessary.

For upstream emissions from fossil-fuel-based hydrogen, please use the figures found in the following peer-reviewed report or justify a decision to use different figures: Robert W. Howarth and Mark Z. Jackson, “How green is blue hydrogen?” Energy Science & Engineering, 26 July 2021 (link).

For the emissions of unburned methane from customer equipment, please use the figures found in the following peer-reviewed report or justify a decision to use different figures: Zachary Merrin and Paul W. Francisco, *Unburned Methane Emissions from Residential Natural Gas Appliances* (link).

b) Please indicate whether the following emissions are accounted for in Guidehouse's study and the above figure:

i. Upstream emissions for fossil gas consumed in Ontario (e.g. emissions from extraction, transportation leaks, etc.);
ii. Upstream emissions for hydrogen produced out-of-province and consumed in Ontario, including:

A. Uncaptured GHG emissions from the production of hydrogen from methane and the carbon capture process;
B. Fugitive methane emissions;
C. Fugitive hydrogen emissions (H2 is an indirect greenhouse gas, which reacts with other greenhouse gases in the atmosphere to increase their global warming potential);

iii. Fugitive methane emissions in Ontario from pipelines;
iv. Fugitive hydrogen emissions in Ontario from pipelines;
v. Fugitive methane emissions in Ontario from behind-the-meter equipment or pipes;
vi. Fugitive hydrogen emissions in Ontario from behind-the-meter equipment or pipes; and
vii. Emissions unsuccessfully captured in CCUS projects in Ontario.

c) Please provide a list of emissions related to RNG or hydrogen that are not accounted for in Guidehouse's study aside from those listed in (b), if any.

d) Please express the impact in terms of tCO2e of (i) 1 m3 of fugitive methane; (ii) 1 m3 of combusted methane; and (iii) 1 m3 of fugitive hydrogen.

e) What is Guidehouse's best estimate of the the global warming potential (GWP) of carbon dioxide, methane, and hydrogen? With respect to hydrogen, is the GWP 11 as per more recent research or 5.8 as per older studies ?

f) Please provide a copy of the above table in the units of MW/yr.

g) Please provide a best estimate of the GHG emissions (tCO2e/m3) from:

i. Upstream emissions (extraction and fugitive) for fossil gas consumed in Ontario, on average;
ii. Upstream emissions for hydrogen produced out-of-province and consumed in Ontario, on average, with and without CCUS;

iii. Fugitive emissions from leaks in Enbridge's gas infrastructure, on average;
iv. Fugitive emissions from behind-the-meter gas equipment and pipes, on average.

h) Please discuss the likely impact of hydrogen being a smaller molecule on the impact on the percentage of leakage from gas pipelines in comparison to methane. Please provide any studies that can be efficiency located on this topic.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Guidehouse declines to update the figure as requested, because Guidehouse does not concur with the upstream emissions factors presented in Howarth and Jackson (2021), for reasons stated in Guidehouse's response at Exhibit I.1.10-ED-58. In addition, accounting for lifecycle emissions only for gaseous fuels, without doing a full lifecycle assessment for all aspects of the gas and electricity systems, may lead to a biased result. A full lifecycle assessment for the energy systems in the report was out of scope for the report and is not feasible to complete in the interrogatory response period.

b) The following table indicates the emissions that are accounted for in the P2NZ Study and in Figure ES-2 "Carbon Emissions (2020-2050)

Table: Emissions Accounted for in the Guidehouse P2NZ Study

Emissions Stream	**Included / Not Included**
(i) Upstream emissions for fossil gas consumed in Ontario (e.g., emissions from extraction, transportation leaks, etc.)	Emissions from transmission pipeline losses are included; Emissions from extraction and processing activities are included for fossil gas consumed outside of CCS and blue hydrogen applications
(ii) Upstream emissions for hydrogen produced out-of-province and consumed in Ontario, including:	
(A) Uncaptured GHG emissions from the production of hydrogen from methane and the carbon capture process	Not Included

(B) Fugitive methane emissions	Not Included
(C) Fugitive hydrogen emissions (H2 is an indirect greenhouse gas, which reacts with other greenhouse gases in the atmosphere to increase their global warming potential)	Not Included
(iii) Fugitive methane emissions in Ontario from pipelines;	Included
(iv) Fugitive hydrogen emissions in Ontario from pipelines	Not Included
(v) Fugitive methane emissions in Ontario from behind-the-meter equipment or pipes	Not Included
(vi) Fugitive hydrogen emissions in Ontario from behind-the-meter equipment or pipes	Not Included
(vii) Emissions unsuccessfully captured in CCUS projects in Ontario	Included

c) Guidehouse has not noted any other RNG- or hydrogen-related emissions streams that are not listed in the table in part b).

d)

i. Guidehouse declines to provide the CO2-equivalent emissions of fugitive methane, because Guidehouse did not use an explicit assumption for this parameter. To estimate the emissions associated with gas transmission and midstream (GTM) fugitive methane, Guidehouse referenced Enbridge's Resilient Energy Infrastructure report,[1] which describes the impact of fugitive methane in terms of tonnes CO2e per billion cubic feet (bcf) of natural gas supplied. Counting Scope 1 and Scope 2 emissions for GTM, Guidehouse estimated fugitive methane emissions impacts using the parameter of 1,464.7 tCO2e per bcf of natural gas supplied.

ii. The P2NZ analysis used the emission factor of 0.001876 tCO2e/m3 for natural gas combustion.[2] Guidehouse divided "GHG Emissions by Energy Source (MTCO2e)" by "Energy Use by Energy Source (PJ)" to get 0.0483 MTCO2e/PJ, which was then converted to units of tCO2e/m3. Guidehouse also accounted for

[1] Enbridge (2019). "Resilient Energy Infrastructure Addressing Climate-Related Risks and Opportunities." p.25.
https://www.enbridge.com/~/media/Enb/Documents/Reports/Resilient_Energy_Infrastructure_report_FINAL.pdf
[2] NRCan National Energy Use Database, 2019 Version.

the CH4 and N2O emissions of RNG combustion using the emission factor 0.0113 kgCO2e/m3 from the National Inventory Report.[3]

iii. Guidehouse declines to answer this question because Guidehouse did not estimate the impacts of fugitive hydrogen. Hydrogen is not currently a reportable emission in Ontario.

e) Guidehouse has not independently evaluated the global warming potential of carbon dioxide, methane, or hydrogen. For the P2NZ study, Guidehouse did not need to apply GWP factors, because the data sources referenced by the analysis provided emissions factors in terms of CO2-equivalent emissions.

f) Guidehouse declines to answer this question because it is unclear to which table the question refers.

g)

i. Guidehouse assumed an emissions rate of 0.000052 tCO2e/m3 to account for fugitive emissions from gas transmission and midstream (GTM) for fossil gas consumed in Ontario. For fossil gas consumed in end user applications (not including blue hydrogen and CCS processes), Guidehouse assumed an emissions rate of 0.00021 tCO2e/m3 for upstream emissions from methane production and processing. /u

ii.-iv Guidehouse declines to answer these questions because Guidehouse did not estimate the emissions associated with upstream hydrogen production, methane distribution (aside for upstream and midstream emissions, noted in (i)), or fugitive behind-the-meter methane emissions.

h) Guidehouse declines to answer these questions, as Guidehouse has not independently studied the leak flow rates of hydrogen in gas pipelines.

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[3] Environment and Climate Change Canada. (2022, April 14). 2022 National Inventory Report 1990-2020: Greenhouse Gas Sources and Sinks in Canada. Part 2. Table A6.1-3.

ENBRIDGE GAS INC.

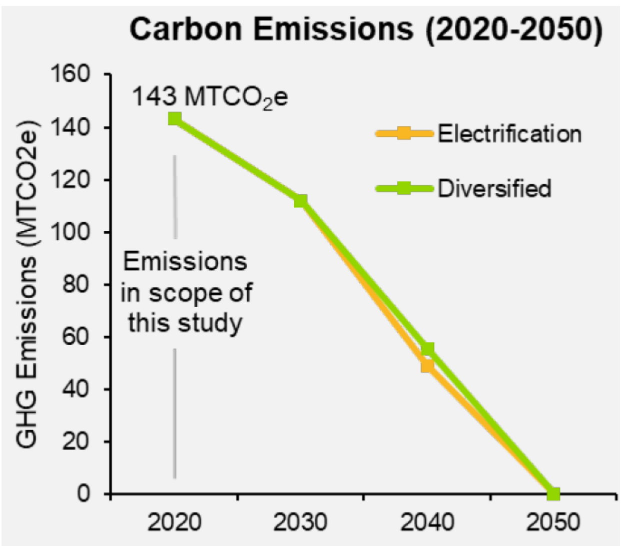
Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 3

Preamble:



Question(s):

a) Please provide an updated version of the above figure that does not factor-in negative emissions (e.g. direct air capture).

b) Please complete the following table indicating the volume and cost of the negative emissions (e.g. direct air capture) in each of the scenarios:

Negative Emissions by Scenario				
	2020	2030	2040	2050
Diversified scenario				
Negative emissions (tCOe2/yr)				
Breakdown of negative emission sources				
Cost to achieve negative emissions ($/yr)				
Electrification scenario				
Negative emissions (tCOe2/yr)				

Breakdown of negative emission sources				
Cost to achieve negative emissions ($/yr)				

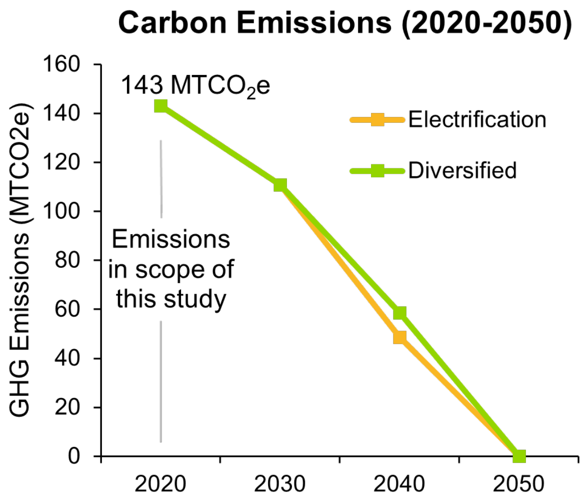
c) Please provide a breakdown of the origin of the remaining emissions sources from gaseous fuels (e.g. industrial, power generation, etc.) by scenario:

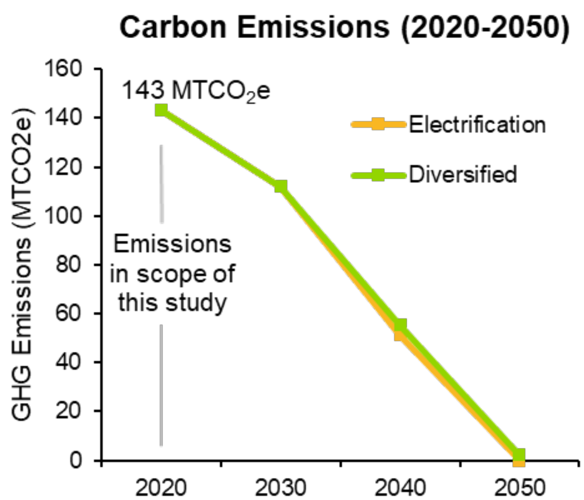
GHG Emission Sources by Scenario				
	2020	2030	2040	2050
Diversified scenario				
Source 1 (tCO2e/yr)				
…				
Source n (tCO2e/yr)				
Electrification scenario				
Source 1 (tCO2e/yr)				
…				
Source n (tCO2e/yr)				

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) The figure below shows carbon emissions from 2020-2050, omitting negative emissions from biomass paired with CCS technology. Guidehouse did not model direct air capture or other negative emissions technologies in the P2NZ study





b) The Table 1 describes the volume and cost of the negative emissions in each of the scenarios.

Table 1
Negative Emissions by Scenario

	2020	2030	2040	2050
Diversified scenario				
Negative emissions (MTCOe2/yr)	N/A	N/A	N/A	-2.40
Breakdown of negative emission sources	N/A	N/A	N/A	Biomass + CCS

/u

Cost to achieve negative emissions ($/yr)[1]	N/A	N/A	N/A	$605 M	/u
Electrification scenario					
Negative emissions (MTCOe2/yr)	N/A	N/A	-2.40	-4.81	
Breakdown of negative emission sources	N/A	N/A	Biomass + CCS	Biomass + CCS	
Cost to achieve negative emissions ($/yr)[1]	N/A	N/A	$605 M	$1,210 M	/u

c) The Table 2 below describes emissions from technologies modelled in the P2NZ study.

Table 2
GHG Emission Sources by Scenario (MTCOe2/yr)

	2020	2030	2040	2050	
Diversified scenario					
Anaerobic Digestion	0.00	0.01	0.03	0.05	/u
Fossil gas with point source CCS	0.00	0.27	0.64	0.75	/u
Fossil gas	51.25	49.52	27.86	0.00	/u
Hydrogen production via steam methane reforming with CCS (SMR + CCS)	0.00	0.87	1.63	1.60	/u
Transport Fossil Fuels	76.65	51.10	25.55	0.00	
Non-Gas Building Heating	3.20	2.13	1.07	0.00	
Coke / Coal	12.00	8.00	4.00	0.00	
Electrification scenario					
Anaerobic Digestion	0.00	0.00	0.02	0.02	/u
Fossil gas with point source CCS	0.00	0.00	0.36	0.57	/u
Fossil gas	51.25	49.66	18.04	0.0	/u
Hydrogen production via steam methane reforming with CCS (SMR + CCS)	0.00	0.33	0.86	0.86	/u
Transport Fossil Fuels	76.65	51.10	25.55	0.00	
Non-Gas Building Heating	3.20	2.13	1.07	0.00	
Coke / Coal	12.00	8.00	4.00	0.00	

[1] Annual costs ($/yr) presented here represent the average cost over each decade, including capital and O&M costs.

ENBRIDGE GAS INC.

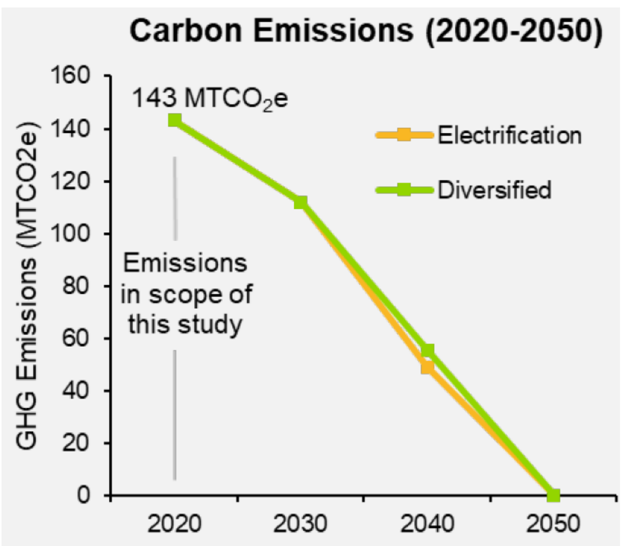
Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

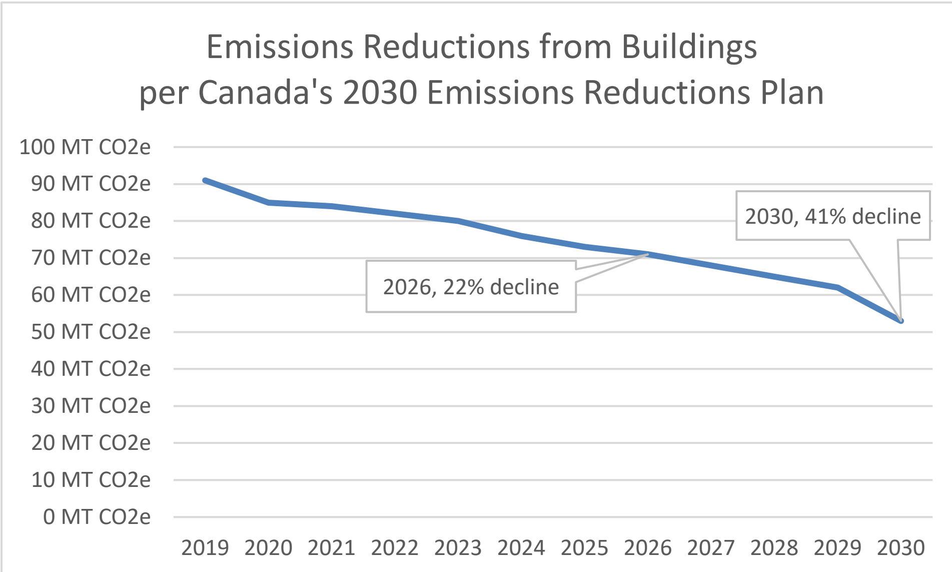
Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 3

Preamble:



Question(s):

a) Please add a line to the above figure to reflect the emissions reductions buildings per Canada's 2030 Emissions Reductions Plan (22% by 2026 and by 41% by 2030), which can be found in this footnote and are shown in the following chart. Please provide a response on a best-efforts basis, making assumptions and stating caveats as necessary. Please provide all underlying sources, calculations, and assumptions. To translate the national emissions reductions for buildings to provincial fossil gas emissions reductions, we recommend the following assumptions: (i) Ontario's share of reductions is proportional to Ontario's share of national emissions and (ii) all or almost all the reductions from buildings are achieved with respect to fossil gas consumption (as it constitutes almost all the GHGs from buildings). However, please use whatever assumptions Guidehouse believes are appropriate.



Response:

The following response was provided by Guidehouse Canada Ltd.:

a) The cited Figure ES-2 includes Ontario-specific emissions for the buildings, transportation, industry, and power sectors over a 30-year period. Intervenors requested the incorporation of Canada-wide buildings sector data for a 10-year period. Guidehouse declines to amend the cited Figure ES-2 as requested, on the basis that the geographic, temporal, and sectoral scopes of Figure ES-2 are all different from the data that intervenors request to incorporate.

ENBRIDGE GAS INC.

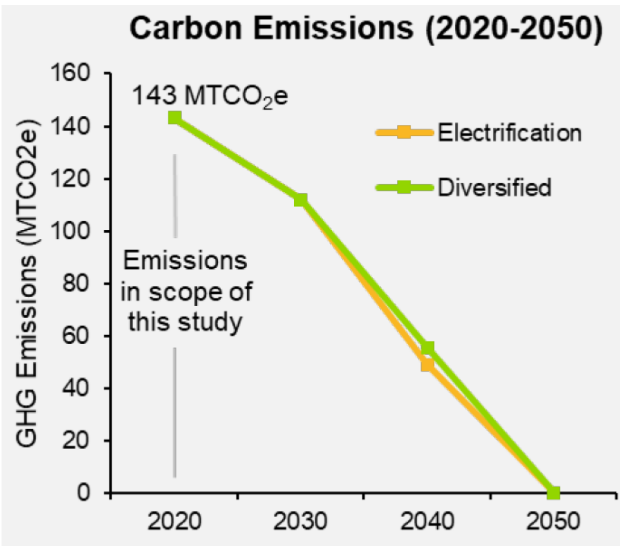
Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 3

Preamble:



Question(s):

a) Please provide a table with a breakdown of the emissions by sector by year (or by decade, if by year is not possible) corresponding to the above table for each of the two scenarios.

b) Please provide a table with a breakdown of the emissions by (i) gaseous fuels and (ii) other sources by year (or by decade, if by year is not possible) corresponding to the above table for each of the two scenarios.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) The following table includes emissions by sector, decade, and scenario.

Emissions by Scenario and Decade (million tCO2e)					
	2020	**2030**	**2040**	**2050**	
Diversified scenario					
Buildings sector	33.4	29.4	14.4	0.4	/u
Transportation sector	76.9	53.8	28.5	0.7	/u
Industrial sector	32.8	27.6	15.5	1.3	/u
Electrification scenario					
Buildings sector	33.4	28.8	10.7	0.1	/u
Transportation sector	76.9	51.2	25.8	0.3	/u
Industrial sector	32.8	30.8	14.5	1.0	/u

b) The following table includes a breakdown of energy system emissions by gaseous fuels and other sources, by decade and scenario, including negative emissions.

Energy System Emissions by Scenario and Decade (million tCO2e)					
	2020	**2030**	**2040**	**2050**	
Diversified scenario					
Renewable natural gas	0.00	0.01	0.03	0.05	/u
Biomass with CCS	0.00	0.00	0.00	-2.40	/u
Natural gas with CCS	0.00	0.27	0.64	0.75	/u
Natural gas	51.25	48.35	25.53	0.00	/u
Hydrogen from natural gas + CCS	0.00	0.87	1.63	1.60	/u
Gaseous fuels total	**51.25**	**49.49**	**27.83**	**0.00**	/u
Other Sources	**91.85**	**61.23**	**30.62**	**0**	
Electrification scenario					
Renewable natural gas	0.00	0.00	0.02	0.02	/u
Biomass with CCS	0.00	0.00	-2.40	-4.81	
Natural gas with CCS	0.00	0.00	0.36	0.57	/u
Natural gas	51.25	49.28	19.19	0.00	/u
Hydrogen from natural gas + CCS	0.00	0.33	0.86	0.86	/u
Gaseous fuels total	**51.25**	**49.61**	**18.02**	**-3.35**	/u
Other Sources	**91.85**	**61.23**	**30.62**	**0**	

ENBRIDGE GAS INC.

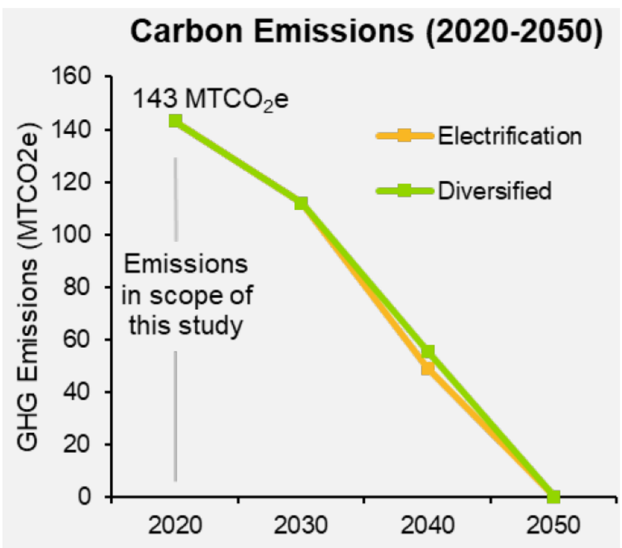
Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 3

Preamble:



Question(s):

a) Please provide a list of measures based on the Guidehouse study that would be attributable to the emissions reductions shown above for each scenario and the emissions reductions from each up to 2028. Please provide an answer on a best-efforts basis, making assumptions and stating caveats as necessary. Please provide all underlying calculations and assumptions. Please use the following format for the figures:

Emissions Reductions Sources by Scenario in 2028		
	Description	Expected reductions by 2028 (tCO2e)
Diversified scenario		
Measure 1		

…		
Measure n		
Electrification scenario		
Measure 1		
…		
Measure n		

b) This response will require both Guidehouse and Enbridge staff. Please complete the following tables comparing the scenarios with the emissions reductions forecast based on the current policies in place and Enbridge's application. Where there is a variance, please explain the variance and describe how it could be closed through additional relief from the OEB over the 2024-2028 period.

Emissions Reductions – Diversified Scenario vs. Enbridge Application				
	Scenario reductions by 2028 (tCO2e)	Forecast reductions by 2028 (tCO2e)	Variance explanation	Possible ways to eliminate variance
Diversified scenario				
Measure 1				
…				
Measure n				

Emissions Reductions – Electrified Scenario vs. Enbridge Application				
	Scenario reductions by 2028 (tCO2e)	Forecast reductions by 2028 (tCO2e)	Variance explanation	Possible ways to eliminate variance
Electrified scenario				
Measure 1				
…				
Measure n				

<u>Response:</u>

The following response was provided by Guidehouse Canada Ltd.:

a-b) Guidehouse declines to respond to this question. The energy demand and supply modeling conducted for the P2NZ study is complex and interactive, and under the current model design we cannot attribute emissions reductions from changes in supply to specific interventions. For example, a mix of different hydrogen production technologies (steam methane reforming with CCS versus electrolysis) are utilized both in Ontario and in neighbouring jurisdictions in each scenario. Therefore, the hydrogen delivered to end user customers to replace methane demand is a blend of these sources, each with their own emissions rate. A comprehensive data table for the emissions associated with each supply resource is provided in the response to Exhibit I.1.10-ED-29.

In addition, Guidehouse estimated emissions reductions on a decade basis and projections are not available for interim years such as the period from 2024 to 2028.

b) Enbridge Gas declines to complete a table that compares the scenarios in P2NZ with emissions reductions forecast based on the current policies in place and Enbridge Gas's application. Emissions reductions for the P2NZ scenarios over the 2024 to 2028 period are not available for the reasons stated in the response from Guidehouse in part a) above and, therefore, a comparison between emissions reductions over this period in the P2NZ scenarios and Enbridge Gas's application is not possible. Additionally, Enbridge Gas is unable to prepare a table of the emissions reductions based on the current policies in place and Enbridge Gas's application because the proposals included within Enbridge Gas's Energy Transition Plan (see Exhibit 1, Tab 10, Schedule 6, Table 1) do not yet have an associated emissions reduction forecast at this time. The Low Carbon Voluntary Program (LCVP) is not being addressed until phase 2 of the Rebasing Proceeding, and the Low Carbon Energy Project (LCEP) Phase 2 proposal will be brought forward in a separate application.

Enbridge Gas notes that in order to compare the emissions reductions based on the proposals within the application to the Diversified Portfolio scenario presented in the Energy Transition Scenario Analysis (ETSA) study, the Company engaged Posterity Group to develop an Energy Transition Initiative (ETI) scenario that is available at Exhibit 1, Tab 10, Schedule 6, Attachment 1. This scenario is based on changes to the assumptions for renewable natural gas (RNG), hydrogen and carbon capture and storage (CCS) that are aligned with the rebasing proposals plus the policy assumptions in the Diversified Portfolio scenario, not current policies as requested in the question.

Regarding additional support from the OEB over the 2024 to 2028 period, Enbridge Gas recommends that as the OEB continues to evolve its processes, frameworks and metrics to consider and account for the energy transition, that it focusses on enabling the most cost-effective, reliable and resilient GHG emissions reductions in Ontario, not solely on electrification. To enable this, Enbridge Gas believes that this would include having the OEB support and endorse integrated gas and electric planning, as discussed at Exhibit 1, Tab 10, Schedule 6, Section 2.4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

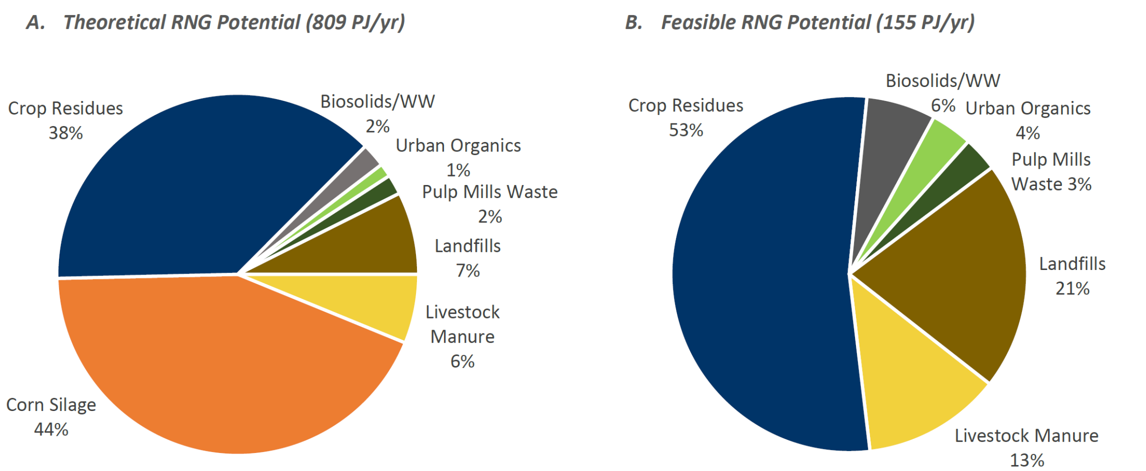
Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 19

Preamble:

“While the supply of RNG in Ontario is currently small and more costly that importing natural gas, the province has significant RNG production potential. Torchlight Bioresources estimated Ontario’s RNG potential via conventional RNG production technologies like anaerobic digestion and landfill gas. Torchlight’s report estimated that Ontario has the potential to produce around 40 PJ per year of RNG supply from wet organic wastes and up to around 240 PJ per year if agricultural residues are included. These agricultural residues reflect waste products such as corn stover and corn silage, and not new crop production that would need to be redirected to RNG production. This RNG potential represents roughly 4%-26% of Ontario’s annual natural gas demand. ”

Question(s):

a) The following figure from page 56 of the Torchlight Bioresources report relied on by Guidehouse study states that the “feasible RNG potential” is 155 PJ/yr for all of Canada. In contrast, Guidehouse states that Ontario’s RNG potential is 240 PJ/yr and includes 171 PJ/yr of RNG in its diversified scenario by 2050 (p. 40). Please provide the “feasible” RNG potential for Ontario. If necessary, please contact Torchlight Bioresources to determined the specific figure for Ontario. Please indicate in the response if they have been contacted.



<u>Response:</u>

The following response was provided by Guidehouse Canada Ltd.:

a) Page 18 of the *Pathways to Net Zero Emissions for Ontario* Study contains a typographical error in its reference to 240 PJ/year of RNG production potential. This value should be stated as 224 PJ/year of theoretical conventional RNG potential, a value Guidehouse referenced from Figure 19 of the Torchlight Report (reproduced below). Guidehouse used the 224 PJ/year value in calculations for the *Pathways* Study. The Torchlight Study does not include an estimate of feasible RNG production potential in Ontario, and Guidehouse is not aware of any such estimate. Guidehouse declined to contact Torchlight Bioresources for this estimate.

Figure 19. Annual Theoretical Conventional RNG Potential, by Province

Province/Territory	RNG Potential (Including Herbaceous)	RNG Potential (Excluding Herbaceous)	Feedstocks Exceeding 2.5 PJ/yr Potential
British Columbia	20	16	Corn silage, hog manure, landfills, pulp mills
Alberta	105	15	Crop residues, corn silage, landfills, cattle feedlot manure
Saskatchewan	112	3	Crop residues, corn silage
Manitoba	70	4	Crop residues, corn silage
Ontario	224	41	Corn silage, landfills, crop residues, biosolids/wastewater, hog manure, poultry manure, urban organics
Quebec	116	38	Corn silage, landfills, hog manure, crop residues, pulp mills, biosolids/wastewater, dairy manure
New Brunswick	5	4	-
Nova Scotia	4	2	-
Prince Edward Island	2	0	-
Newfoundland and Labrador	1	1	-
Canada	**660**	**123**	**All**

Source: TorchLight Bioresources (2020). “Renewable Natural Gas (Biomethane) Feedstock Potential in Canada.” p.27. Available at: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf?la=en

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 19

Preamble:

"While the supply of RNG in Ontario is currently small and more costly that importing natural gas, the province has significant RNG production potential. Torchlight Bioresources estimated Ontario's RNG potential via conventional RNG production technologies like anaerobic digestion and landfill gas. Torchlight's report estimated that Ontario has the potential to produce around 40 PJ per year of RNG supply from wet organic wastes and up to around 240 PJ per year if agricultural residues are included. These agricultural residues reflect waste products such as corn stover and corn silage, and not new crop production that would need to be redirected to RNG production. This RNG potential represents roughly 4%-26% of Ontario's annual natural gas demand. "

Question(s):

a) Is the 40 PJ to 240 PJ of Ontario RNG potential that Guidehouse references from the Torchlight Bioresources report the "feasible potential" or the "theoretical conventional RNG potential" (per p. 27 of the Torchlight report)? If neither, please explain.

b) Please describe the difference between the "feasible" and "theoretical" RNG potential as described in the Torchlight Bioresources report.

c) Please confirm that Torchlight Bioresources estimates that there is "660 PJ of theoretical conventional RNG potential" in Canada (per p. 54) and 155 PJ/yr of "feasible RNG potential" in Canada (p. 56). If not, please explain.

d) Please confirm that, according to Torchlight Bioresources, the theoretical conventional RNG potential in Canada is over 4.2 times the feasible RNG potential.

e) Please provide the Ontario RNG consumption assumed in the Guidehouse report for each scenario annually between 2020 and 2050. Please express the answer in a table showing both m3 and PJ.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Guidehouse refers to the response at Exhibit I.1.10-ED-31 part a). The technical potential was used as a simplifying assumption, and Guidehouse notes that the market for RNG spans North America, and Ontario's consumption of RNG will not be bounded by the potential for in-province RNG production.

b) Guidehouse understands that Torchlight estimated the "theoretical" potential as the sum of potential production from all RNG feedstocks, without considering the economics of individual projects. Guidehouse understands that Torchlight estimated the "feasible" RNG potential by excluding sources of RNG feedstock where RNG production may be limited by economic constraints. For example, Torchlight notes that small landfill or anaerobic digestion projects may find RNG production and pipeline injection uneconomical due to economies of scale or distance from natural gas pipelines. Torchlight also notes that, "The percentage of feedstock actually converted to RNG will be strongly impacted by pricing and availability of complementary co-digestion feedstocks."

   Guidehouse expects that the definition of "feasibility" will evolve over time with changing commodity prices and escalating carbon taxes, and as pilot projects demonstrate new methods of RNG collection that overcome economy-of-scale issues.

c) Guidehouse confirms that the Torchlight Bioresources 2020 report estimates there is 809 PJ of total theoretical RNG potential (p.iii), 660 PJ of theoretical conventional RNG potential in Canada (p. 54) and 155 PJ/yr of "feasible RNG potential" in Canada (p.iii).

d) Guidehouse confirms that, according to Torchlight Bioresources, the theoretical conventional RNG potential in Canada is over 4.2 times the feasible RNG potential.

e) For the *Pathways to Net Zero Emissions for Ontario* Study, Guidehouse estimated RNG consumption on a decade basis. Table 1 provides the Ontario RNG consumption assumed in the Guidehouse report for each scenario between 2020 and 2050.

Table 1
Projected RNG Consumption in Ontario, by scenario and decade

Scenario	Unit	2020	2030	2040	2050	
Diversified Scenario	bcm	0.0	1.2	2.5	4.7	/u
	PJ	0.0	44.3	91.4	170.6	/u
Electrification Scenario	bcm	0.0	0.0	1.6	2.0	/u
	PJ	0.0	0.0	59.0	72.4	/u

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 19 & 40

Preamble:

Per p. 40: "The increase in supply capacity for RNG production will be primarily via anaerobic digestion, reaching 171 PJ by 2050 in the Diversified scenario and 139 PJ in the Electrification scenario. These figures represent a significant share of Ontario's RNG potential, estimated to be 240 PJ. "

Per p. 19: "Torchlight's report estimated that Ontario has the potential to produce around 40 PJ per year of RNG supply from wet organic wastes and up to around 240 PJ per year if agricultural residues are included. These agricultural residues reflect waste products such as corn stover and corn silage, and not new crop production that would need to be redirected to RNG production. This RNG potential represents roughly 4%-26% of Ontario's annual natural gas demand. "

Question(s):

a) The only reference we can find in the Torchlight Bioresources report that provides a breakdown for the Ontario potential is the "Theoretical Conventional RNG Potential" at page 27 of the report (excepted below). That lists the "theoretical" potential as being 224 PJ (including herbaceous) and 41 PJ (excluding herbaceous). Is Guidehouse's reference to Ontario's RNG potential being 240 PJ a typo? If not, please explain how Guidehoue can assume an RNG potential based on the Torchlight Bioresources report that is higher than even the "theoretical potential" in the Torchlight Bioresources report, let alone the feasible potential in that report.

Figure 19. Annual Theoretical Conventional RNG Potential, by Province

Province/Territory	RNG Potential (Including Herbaceous)	RNG Potential (Excluding Herbaceous)	Feedstocks Exceeding 2.5 PJ/yr Potential
British Columbia	20	16	Corn silage, hog manure, landfills, pulp mills
Alberta	105	15	Crop residues, corn silage, landfills, cattle feedlot manure
Saskatchewan	112	3	Crop residues, corn silage
Manitoba	70	4	Crop residues, corn silage
Ontario	224	41	Corn silage, landfills, crop residues, biosolids/wastewater, hog manure, poultry manure, urban organics
Quebec	116	38	Corn silage, landfills, hog manure, crop residues, pulp mills, biosolids/wastewater, dairy manure
New Brunswick	5	4	-
Nova Scotia	4	2	-
Prince Edward Island	2	0	-
Newfoundland and Labrador	1	1	-
Canada	**660**	**123**	**All**

b) Why does Torchlight Bioresources differentiate between the potential including and excluding herbaceous? Is that because herbaceous feedstocks have competing uses and therefore may not be available for RNG?

c) Please provide a breakdown of the herbaceous feedstocks available in Ontario (PJ), indicating which are currently used for other purposes.

d) How much of Ontario’s RNG potential (JP) is from corn silage/stover?

e) Please confirm that corn silage/stover can be used as fodder, bedding, or a soil amendment.

f) Approximately how much (PJ) of Ontario’s available corn silage/stover is already being used as fodder, bedding, or a soil amendment.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Page 18 of the *Pathways to Net Zero Emissions for Ontario* study contains a typographical error in its reference to 240 PJ/year of RNG production potential. This value should be stated as 224 PJ/year of theoretical conventional RNG potential, a value Guidehouse referenced from Figure 19 of the Torchlight report. Guidehouse used the 224 PJ/year value in calculations for the *Pathways* study.

b) Guidehouse understands that the Torchlight Bioresources report justifies the differentiation between herbaceous and non-herbaceous feedstocks on page 57 of the report, where it states, “While crop residues can certainly contribute to the RNG total, the reality is that surplus crop residues can be converted to thermal energy (building heat, process heat) at a higher efficiency and with lower costs using combustion technology.”

   Guidehouse notes that RNG has advantages over crop residues as a heating fuel in that RNG may be transported via existing gas networks, and RNG may be used as a drop-in replacement for conventional natural gas that does not require conversion of existing gas-fired heating equipment.

c) Guidehouse understands that the Torchlight Bioresources report does not provide a comprehensive estimate of herbaceous feedstocks available in Ontario, and Guidehouse is unaware of other sources for this data.

d) Guidehouse used the information provided for Ontario census divisions in Appendix 1 of the Torchlight Bioresources report to calculate a sum of the corn silage resource potential available in Ontario. The data provided in Appendix 1 of the Torchlight Bioresources indicates that 167.3 PJ of Ontario’s RNG resource potential is from corn silage, which Guidehouse understands is a subset of herbaceous feedstocks.

e) Section 3.1 of the Torchlight Bioresources report indicates that corn silage/stover can be used as fodder, bedding, or a soil amendment. Guidehouse references the following quotes from page 30 of the Torchlight Bioresources report:

   - “Some stover must remain on the soil surface following harvest to support soil and ecosystem health…”
   - “At the present time, stover is underused with minor amounts serving as AD feedstock or as feed or bedding for dairy cattle.”
   - “Corn silage is produced annually from feed corn as an energy-dense dairy cattle feed.”

f) Figure 21 of the Torchlight Bioresources report indicates that in the current situation (Scenario A of Figure 21), 3.8 megatonnes of silage is used as livestock feed, and 6.7 megatonnes of stover is used for soil retention. The Torchlight report does not express these amounts in terms of petajoules, nor does it provide a factor for converting megatonnes of silage/stover into petajoules.

[’ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 19 & 40

Preamble:

Per p. 19 of the Guidehouse report: “Torchlight’s 240 PJ estimate is based on anaerobic digestion and landfill potential and does not reflect more advanced RNG production technologies like biomass gasification or power-to-gas, which are not yet commercially available.”

Per p. 40 of the Guidehouse report: “Other RNG production technologies such as biomass gasification do not play major roles in RNG supply today; however, local conditions and the availability of low-cost biomass feedstock (such as in Northern Ontario) may encourage the development of gasification plants in the future.”

Per p. 54 of the Torchlight Bioresources report: “This bottom-up resource analysis has shown the theoretical potential for RNG production in Canada is approximately 809 PJ per year … Of this 809 PJ, 660 PJ is the theoretical potential for conventional RNG. This excludes precommercial wood-to-gas pathways of gasification and methanation, and pyrocatalytic hydrogenation (150 PJ). As identified in Section 4.3 and as stated by stakeholders in a recent national survey, these technologies face major scale-up hurdles.47,59 In addition, if RNG from wood is used for building or process heat, the production pathway will be notably lower efficiency and higher capital cost than direct combustion of solid wood fuel.

Question(s):

a) Does Guidehouse agree that RNG from the gasification of wood is “notably lower efficiency and higher capital cost than direct combustion of solid wood fuel” if the RNG is to be used to generate heat?

b) Does Guidehouse believe it is likely that RNG from biomass gasification will become cost-effective?

c) Approximately how much does it cost ($/m3) to produce RNG from biomass gasification?

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Guidehouse agrees that, at present, the production of RNG from the gasification of wood is lower efficiency and higher capital cost than direct combustion of solid wood fuel if the RNG is to be used to generate heat. Guidehouse notes that RNG has advantages over solid wood as a heating fuel in that RNG may be transported via existing gas networks, and RNG may be used as a drop-in replacement for conventional natural gas that does not require conversion of existing gas-fired heating equipment.

b) Guidehouse expects that development and commercialization of biomass gasification technologies will lead over time to improved process efficiencies and reduced costs. The cost-effectiveness of biomass gasification will be influenced by many factors, including the commodity cost of competing fuels, escalating carbon taxes, and potential incentives for alternative fuel production. Given the uncertainties around these and other influences, Guidehouse cannot foresee whether biomass will become cost-effective in the future.

c) Guidehouse has not independently assessed the cost of producing RNG from biomass gasification.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 19 & 40

Preamble:

Per p. 40 of the Guidehouse report: “The increase in supply capacity for RNG production will be primarily via anaerobic digestion, reaching 171 PJ by 2050 in the Diversified scenario and 139 PJ in the Electrification scenario. These figures represent a significant share of Ontario’s RNG potential, estimated to be 240 PJ. ”

Per page 54 of the 2017 MACC report for the OEB:

Table 22 Summary of the National and Ontario Provincial RNG Potential in 2028 by Feedstock

Feedstock	National Potential by 2028 (million m^3/yr)	National Potential by 2028 (tCO_2/yr)	Ontario Potential by 2028 (million m^3/yr)	Ontario Potential by 2028 (tCO_2/yr)	LCOE ($\$/m^3$)	Notes
Landfill gas	290	540,000	113	210,000	\$0.33-\$0.82	Evaluated 5 different sized facilities based on survey referenced in Canadian Biogas Study; linked to study for Environment Canada
WWT gas	180	340,000	71	135,000	\$0.48-\$3.73	Evaluated 4 different sized facilities – ICF analysis
Animal manure	874	1,640,000	191	360,000	\$0.87-\$1.66	Considered 3 different farms (Electrigaz study): baseline, large, and co-op
SSO residential & commercial	300	560,000	110	210,000	\$2.90	Assumed a single facility capable of processing 60,000 tonnes/yr per Canadian biogas study. Larger/smaller facilities conceivable

Question(s):

a) What is Guidehouse's best estimate of Ontario's RNG potential by 2028? Please provide a breakdown by feedstock, including the price for each ($/m3).

b) What are the conversion factors between (i) $/m3 and $/PJ of RNG, and (ii) m3 to PJ of RNG?

c) Please fill out the following table comparing the Ontario RNG potential and cost per the above-referenced OEB report with Guidehouse figures.

Comparison of 2028 RNG Potential, Consumption & Cost Figures OEB MACC vs Guidehouse						
Feedstock	**Potential per OEB Study (M m3/yr)**	**Potential per Guidehouse estimate (M m3/yr)**	**Consumption per diversified scenario (M m3/yr)**	**Consumption per electrified scenario (M m3/yr)**	**Cost per OEB Study ($/m3)**	**Cost per Guidehouse estimate ($/m3)**
[E.g. landfill gas, WWT gas, manure, etc.]						

d) Please file a copy of all studies estimating the RNG potential in Ontario that Guidehouse is aware of.

e) Please summarize the conclusions of RNG potential studies referred to in (d) regarding Ontario's RNG potential in the following table:

Ontario's RNG Potential – Comparison of Report Conclusions					
Feedstock	**OEB MACC (potential year)[1]**	**Torchlight Bioresources (potential year)**	**Report 3 (potential year)**	**…**	**Report n (potential year)**
[E.g. landfill gas, WWT gas, manure, etc.]					

[1] i.e. the year in which the stated potential is described in the report as being available.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Guidehouse declines to answer this question because Guidehouse has not independently estimated Ontario's RNG potential in 2028.

b) Guidehouse used a conversion factor of 1 million m^3 RNG = 0.0388 PJ RNG.

c) Guidehouse declines to complete the table as specified because (i) Guidehouse's analysis estimated the required RNG production capacity on a decade basis (i.e., capacity in 2030, 2040, and 2050) and did not estimate the RNG potential in the year 2028; and (ii) Guidehouse's approach to cost modeling did not determine commodity prices of RNG on a $/$m^3$ basis.

   As illustrated in Figure 17 and Table A-8 of the P2NZ report, Guidehouse estimates that the required annual production of RNG in 2030 would be 49 PJ/year (about 1,263 million m^3/year) in the Diversified scenario and 1 PJ/year (about 26 million m^3/year) in the Electrification scenario.

   Guidehouse's approach to cost modeling did not determine commodity costs of RNG on a $/$m^3$ basis. Instead, Guidehouse accounted for the cost of RNG supplies by (1) determining the required production capacity by decade, (2) estimating the capital costs of developing RNG production capacity, and (3) estimating the fixed and variable O&M costs of using this capacity to produce RNG. Table A-11 of the P2NZ report describes the capital and O&M costs assumed for RNG production in 2030, 2040, and 2050.

d) Guidehouse is aware of the following studies of RNG potential in Ontario:

   i. Torchlight Bioresources (2020). "Renewable Natural Gas (Biomethane) Feedstock Potential in Canada." Available at: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf?la=en
   ii. Kelleher Environmental, Robins Environmental (2013). Canadian biogas study – benefits to the economy, environment and energy. Technical Document. Prepared for the Canadian Biogas Association. See Table 11. Available at: https://biogasassociation.ca/images/uploads/documents/2014/biogas_study/Canadian_Biogas_Study_Technical_Document_Dec_2013.pdf

iii. Alberta Research Council (2010). “Potential Production of Methane from Canadian Wastes.” Available at: https://biogasassociation.ca/images/uploads/documents/2010/Potential_Production_of_Methane_from_Canadian_Wastes-ARC_FINAL_Report-Sept_23_2010.doc

e) Guidehouse declines to complete the table as specified. The reports cited in (d) are available for public review. However, the feedstock definitions and timelines for potential resource availability are not consistently defined, so a side-by-side comparison of results from these reports is not possible.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 19, 40, & A-5

Preamble:

The following questions focus on the cost of RNG. Responses are needed to test and analyze (i) the Guidehouse report; (ii) the Application's reliance on the Guidehouse report; and (iii) Enbridge's assertion that its proposed capital spending likely will not be stranded because it can be used in the future for a large quantity of cost-effective renewable natural gas.

Question(s):

a) Please provide all assumptions in the Guidehouse report regarding the cost of RNG ($/m3). Please explain the basis of those assumptions, including the assumed feedstocks and assumed prices for each feedstock. Please provide all sources.

b) Please complete the following tables:

RNG Volumes and Cost by Feedstock – Diversified Scenario				
	2020	**2030**	**2040**	**2050**
Feedstock 1				
Volume (m3)				
Unit cost ($/m3)				
…				
Feedstock n				
Volume (m3)				
Unit cost ($/m3)				
Total of all feedstocks				

Volume (m3)				
Unit cost – weighted average ($/m3				

RNG Volumes and Cost by Feedstock – Electrified Scenario				
	2020	**2030**	**2040**	**2050**
Feedstock 1				
Volume (m3)				
Unit cost ($/m3)				
…				
Feedstock n				
Volume (m3)				
Unit cost ($/m3)				
Total of all feedstocks				
Volume (m3)				
Unit cost – weighted average ($/m3)				

c) If Guidehouse has data to complete the tables in (b) on an annual basis, please provide those tables on an annual basis.

d) Please file a copy of all studies estimating the RNG cost that would be applicable to Ontario that Guidehouse is aware of. Please include the studies that Guidehouse relied on, as well as the studies that Guidehouse decided not to rely on (indicating why it chose not to rely on them).

e) Please summarize the conclusions of the RNG cost studies referred to in (m) regarding in the following table:

RNG Cost in Ontario ($/m3) – Comparison of Report Conclusions					
Feedstock	**Report 1 (year)**[1]	**Report 3 (year)**	**Report 3 (year)**	**…**	**Report n (year)**
Feedstock 1					
…					
Feedstock n					
Weighted average					

Response:

The following response was provided by Guidehouse Canada Ltd.:

a-e) Guidehouse declines to answer the questions regarding unit costs of RNG production. The purpose of the P2NZ report was to estimate the total costs for each scenario to achieve net-zero emissions by 2050. To estimate total costs, Guidehouse accounted for the capital cost of new RNG projects (CONE), the fixed O&M costs (FOM) of operating RNG production capacity regardless of output, and the variable O&M costs (VOM) which scale based on production volume. The CONE and FOM costs for anaerobic digestion are provided in Table A-11 of the P2NZ study. Guidehouse derived these costs from a 2021 U.S. EPA report[2] that describes the capital and O&M costs of a gas collection and flare system (page 4-3) and the capital and O&M costs of a typical RNG pipeline-injection project with a 2-mile pipeline and a 15-year lifetime (page 4-10). For the infrastructure needed to upgrade and inject RNG into natural gas networks, Enbridge Gas Inc. provided Guidehouse with capital and O&M cost estimates based on a sample of projects scoped by Enbridge Gas.

Guidehouse did not estimate a cost per unit production of RNG, as the intent of the study was not to model commodity costs or market prices for RNG.

Guidehouse cannot determine the cost per unit production of RNG from the output of our Low Carbon Pathways model because the cost per unit production would include other project parameters (e.g., taxes, cost of financing, etc.) that we have not estimated.

[1] i.e. The year that the cost estimate relates to if it is not a current-year estimate.
[2] U.S. EPA (2021). “LFG Energy Project Development Handbook.” pp. 4-3 to 4-10. Available at: https://www.epa.gov/system/files/documents/2021-07/pdh_full.pdf

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 20

Preamble:

"Prior studies have assessed CCS options in Ontario and have determined that the only sequestration option is geological sequestration in saline aquifers. Carbon dioxide is expected to be stored in these aquifers for long periods, from one hundred years to several thousand years depending on the size, properties, and location of the reservoir. Prior studies identified two different major reservoirs appropriate for CCS in southwestern Ontario: one located in the southern part of Lake Huron and the other located inside Lake Erie. These sites have approximate storage capacities of 289 million and 442 million tonnes of CO2 emissions. "

Question(s):

a) What is the average lifetime of the equipment needed for a CCS facility?

b) For economic assessments of CCS facilities, what are the typical assumed economic lifetimes? In other words, approximately how many years of operating revenue would be required to recoup the upfront capital investment?

c) Please complete the following table indicating the annual and cumulative quantity of CO2 to be sequestered in Ontario under the two scenarios. For years beyond 2050, please extrapolate the annual CO2 to be sequestered based on the previous 5-year trend (or make, state, and explain a different assumption if Guidehouse believes a different assumption is warranted for future years). If annual figures are not possible, please provide the figures by decade. This question is meant, in part, to explore how long it would take for the aquifers to be full.

Ontario-Based Carbon Sequestration Volumes by Scenario Annual and Cumulative				
	2020	2021	….	Year in which cumulative total is 731 M t CO2e
Diversified				
Annual (MtCO2)				
Cumulative (MtCO2)				
Electrified				
Annual (MtCO2)				
Cumulative (MtCO2)				
Estimated reservoir capacity	731	731	731	731

d) Please complete the following table indicating the annual and cumulative quantity of CO_2 to be sequestered in Ontario under the scenarios with a breakdown between CCS for blue hydrogen occurring in Ontario (SMR & CCS) and combustion of fossil gas. For years beyond 2050, please extrapolate the annual CO_2 to be sequestered based on the previous 5-year trend (or make, state, and explain a different assumption if Guidehouse believes a different assumption is warranted for future years). This question is meant, in part, to explore how long it would take for the aquifers to be full.

Ontario-Based Carbon Sequestration Volumes by Scenario Annual and Cumulative				
	2020	2021	….	2050
Diversified				
Blue hydrogen consumption (PJ/yr)				
Blue hydrogen CO2 capture (MtCO2e/yr)				
Fossil gas combustion (PJ/yr)				
Fossil gas combustion capture (MtCO2e/yr)				
Total capture (MtCO2e/yr)				

Electrified				
Blue hydrogen consumption (PJ/yr)				
Blue hydrogen CO2 capture (MtCO2e/yr)				
Fossil gas combustion (PJ/yr)				
Fossil gas combustion capture (MtCO2e/yr)				
Total capture (MtCO2e/yr)				

<u>Response:</u>

The following response was provided by Guidehouse Canada Ltd.:

a-b) Guidehouse estimated the typical lifetime of a CCS facility is 25 years. Guidehouse did not estimate the economic lifetime of CCS facilities.

c-d) Guidehouse calculated the annual consumption of hydrogen and natural gas and the annual amount of CO_2 storage on a decade basis through the year 2050. The following table indicates the annual consumption of blue hydrogen and natural gas with CCS. The table also states the quantity of CO_2 to be sequestered in Ontario under each scenario, with a breakdown between CCS for blue hydrogen occurring in Ontario (SMR & CCS) and combustion of fossil gas with CCS. Cumulative quantities of stored CO_2 are reported in the table for the year 2050. Page to 41 of the *Pathways to Net Zero Emissions for Ontario* Report states the following: /u

"The CO_2 storage requirements for the Diversified and Electrification scenarios up to 2050 would be satisfied with these two reservoirs. In the Diversified scenario, these two major reservoirs would provide sufficient storage volumes up to 20582063, while in the Electrification scenario, they would be sufficient up to 20772086. /u

Ontario-Based Carbon Sequestration Volumes by Scenario Annual and Cumulative					
	2020	2030	2040	2050	
Diversified					
Blue hydrogen consumption (PJ/yr)	0 / year	146 / year	238 / year	231 / year	/u
Blue hydrogen CO2 capture (MtCO2e/yr)	0.0	10.1 / year	16.5 / year	16.0 / year 255.4 cum.	/u
Fossil gas combustion with CCS (PJ/yr)	0.0	48 / year	116 / year	136 / year	/u
Fossil gas combustion capture (MtCO2e/yr)	0.0	2.3 / year	5.5 / year	6.5 / year 76.6 cum.	/u
Total capture (MtCO2e/yr)	0.0	12.4 / year	22.0 / year	22.5 / year 332.1 cum.	/u
Electrified					
Blue hydrogen consumption (PJ/yr)	0 / year	88 / year	94 / year	90 / year	/u
Blue hydrogen CO2 capture (MtCO2e/yr)	0.0	6.1 / year	6.5 / year	6.2 / year 119.6 cum.	/u
Fossil gas combustion with CCS (PJ/yr)	0.0	0 / year	65 / year	107 / year	/u
Fossil gas combustion capture (MtCO2e/yr)	0.0	0.0 / year	3.1 / year	5.1 / year 33.0 cum.	/u
Total capture (MtCO2e/yr)	0.0	6.1 / year	9.6 / year	11.3 / year 152.6 cum.	/u

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 20

Preamble:

"Prior studies have assessed CCS options in Ontario and have determined that the only sequestration option is geological sequestration in saline aquifers. Carbon dioxide is expected to be stored in these aquifers for long periods, from one hundred years to several thousand years depending on the size, properties, and location of the reservoir. Prior studies identified two different major reservoirs appropriate for CCS in southwestern Ontario: one located in the southern part of Lake Huron and the other located inside Lake Erie. These sites have approximate storage capacities of 289 million and 442 million tonnes of CO2 emissions.[1] "

Question(s):

a) Please provide a map showing the location and size of the potential CCS locations in Ontario.

b) Please confirm that the two potential CCS locations in Ontario fall along the Canada-US border.

c) Would use of the CCS locations in Ontario require an agreement or permit(s) from the United States federal government or a state government in light of the fact that the reservoir crosses the international border?

d) Please provide the cost of CCS in Ontario ($/tCO2e) assumed in the Guidehouse report, the basis for that estimate, identify the CCS projects that serve as the basis for that cost estimate, and describe those CCS projects (e.g. the geologic formation they are in). Please break down the cost into the cost of capturing the CO2 and sequestering it.

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[1] Shafeen, Ahmed & Croiset, Eric & Douglas, Peter & Chatzis, Ioannis. (2004). CO2 sequestration in Ontario, Canada. Part I: Storage evaluation of potential reservoirs. Energy Conversion and Management. 45. 2645-2659. Available: http://dx.doi.org/10.1016/j.enconman.2003.12.003

e) Do the two potential CCS locations in Ontario raise additional challenges (e.g. being under lakes) that may raise costs in comparison to the CCS projects that served as the basis for Guidehouse' estimate of the costs of CCS in Ontario?

Response:

a-b) A map showing the two potential CCS locations in Ontario can be found in Figure 12 of the 2007 Ontario Ministry of Natural Resources report titled "Geological Sequestration of Carbon Dioxide: A Technology Review and Analysis of Opportunities in Ontario".[2] The report identifies the potential capacity of the northern zone at 289 Mt of CO_2 and 442 Mt of CO_2 in the southern zone.

c) The permits that may or may not be required are unknown at this time. Currently the Ministry of Natural Resources and Forestry (MNRF) regulates and permits natural gas production from the Crown land under the Canadian portion of Lake Erie and has indicated, in its "Roadmap towards regulating geologic storage"[3] that it intends to design a framework to regulate commercial-scale geologic carbon storage projects on Crown land and private land.

The following response was provided by Guidehouse Canada Ltd.:

d) Guidehouse did not evaluate costs of Ontario-specific CCS storage. Guidehouse referenced generalized estimates of CCS costs from a 2021 study[1] and a 2019 study[2], both of which provide a broad list of references and cost ranges. The 2021 study references a range of 20 to 50 EUR/tCO_2e, and the 2019 study references figures ranging from 15 to 105 EUR/tCO_2e. Based on these sources, Guidehouse assumed CCS costs of 95 CAD$/t$CO_2$e. This assumption represents an average of a low estimate of 50 EUR /tCO_2e and a high estimate of 80 EUR /tCO_2e.

The sources referenced provide generalized cost estimates that are not tied to specific CCS projects or geologic storage sites, and do not break down costs into costs for capture and for sequestration.

e) Guidehouse declines to answer this question because Guidehouse has not independently compared the challenges or costs of storing carbon in Ontario sites with the CCS cost assumptions referenced in (d) above.

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[2] Government of Ontario. (2007). Geological Sequestration of Carbon Dioxide: A Technology Review and Analysis of Opportunities in Ontario. Ontario Ministry of Natural Resources. https://climateontario.ca/MNR_Publications/276925.pdf
[3] Government of Ontario. (2023, March 6). Geologic carbon storage. Ministry of Natural Resources and Forestry. https://www.ontario.ca/page/geologic-carbon-storage

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 20

Preamble:

“Prior studies have assessed CCS options in Ontario and have determined that the only sequestration option is geological sequestration in saline aquifers. Carbon dioxide is expected to be stored in these aquifers for long periods, from one hundred years to several thousand years depending on the size, properties, and location of the reservoir. Prior studies identified two different major reservoirs appropriate for CCS in southwestern Ontario: one located in the southern part of Lake Huron and the other located inside Lake Erie. These sites have approximate storage capacities of 289 million and 442 million tonnes of CO2 emissions. ”

Question(s):

a) Please confirm that “[s]ignificant uncertainties are associated with the reservoir capacity calculation” underlying the approximate storage capacities of 289 million and 442 million tonnes of CO2 emissions cited in the Guidehouse report.

b) Please confirm that there is a “lack of scientifically sound data to predict a true porosity and permeability” for the formation containing the two potential CSS cites in Ontario.”

c) Please confirm that “one of the major concerns for sequestration is leakage to the atmosphere” and that “occur through abandoned wells” and that:

> “A large number of abandoned and unknown oil wells are present in southwestern Ontario whose status is not well documented. These have been abandoned for the past 20–90 years. There are no updated reports available about the status of cement plugging and its strength. Moreover, the quality and quantity of cement used in the early years might have severely degraded by this time. The reactivity of the injected CO2 (or mixture of gas) with this cement and its consequences needs to be

evaluated. Many of these wells (2500) have no plug end date, which raises questions about their present situation."

d) Please confirm that "[a] detailed investigation is necessary to determine the real status of these wells, their ability to withstand the sequestration pressure and impact on the environment in case of a failure." Please confirm whether Guidehouse included the cost of this investigation in its report.

e) Please confirm that "[u]ncertainties in the reservoir condition during the injection process could lead to an unexpected work load associated with huge cost involvement."

f) Please estimate the "huge cost involvement" described in the above passage from the report cited by Guidehouse. Is this possibility accounted for in the Guidehouse report.

g) Please file a copy of the report in the footnote to the above passage from the Guidehouse report so it can be referred to with an exhibit number. If it is proprietary, please file a copy on a confidential basis.

h) The quote from the Guidehouse report refers to sequestration for "one hundred years to several thousand years." What are the factors that would determine whether the actual amount would be nearer to the top or the bottom of that scale.

<u>Response:</u>

The following response was provided by Guidehouse Canada Ltd.:

(a-c, e) Guidehouse declines to answer this question. Guidehouse has no independent view of the information provided in the referenced study. This topic is not in the scope that Guidehouse studied in this analysis.

d) The cost analysis in the *Pathways to Net Zero Emissions for Ontario* Study does not include costs of an investigation to determine well status prior to CCS. Guidehouse declines to confirm the statement referenced in the question. Guidehouse has no independent view of the information provided in the referenced study. This topic is not in the scope that Guidehouse studied in this analysis.

f) The cost analysis in the *Pathways to Net Zero Emissions for Ontario* Study does not account for unexpected work loads due to uncertainties in reservoir conditions. This topic is not in the scope that Guidehouse studied in this analysis and Guidehouse declines to estimate the costs associated with reservoir condition uncertainties.

g) Guidehouse declines to provide a copy of the referenced report. The requested document is a third party report that Guidehouse paid to access, and Guidehouse does not have permission to reproduce or publish it.

h) The quote from the Guidehouse Report is referenced to the study cited to the *Energy Conversion & Management* journal. Guidehouse has no independent view of the information provided in the referenced study. This topic is not in the scope that Guidehouse studied in this analysis. Guidehouse declines to answer this question.

The following response was provided by Enbridge Gas:

a-e) Enbridge Gas is still evaluating subsurface studies and is optimistic about the feasibility of CCS development in Ontario in conjunction with strong modelling, monitoring and risk management practices underpinned by regulatory and technical standards requirements. The Company will provide more information in future forums.

ENBRIDGE GAS INC.

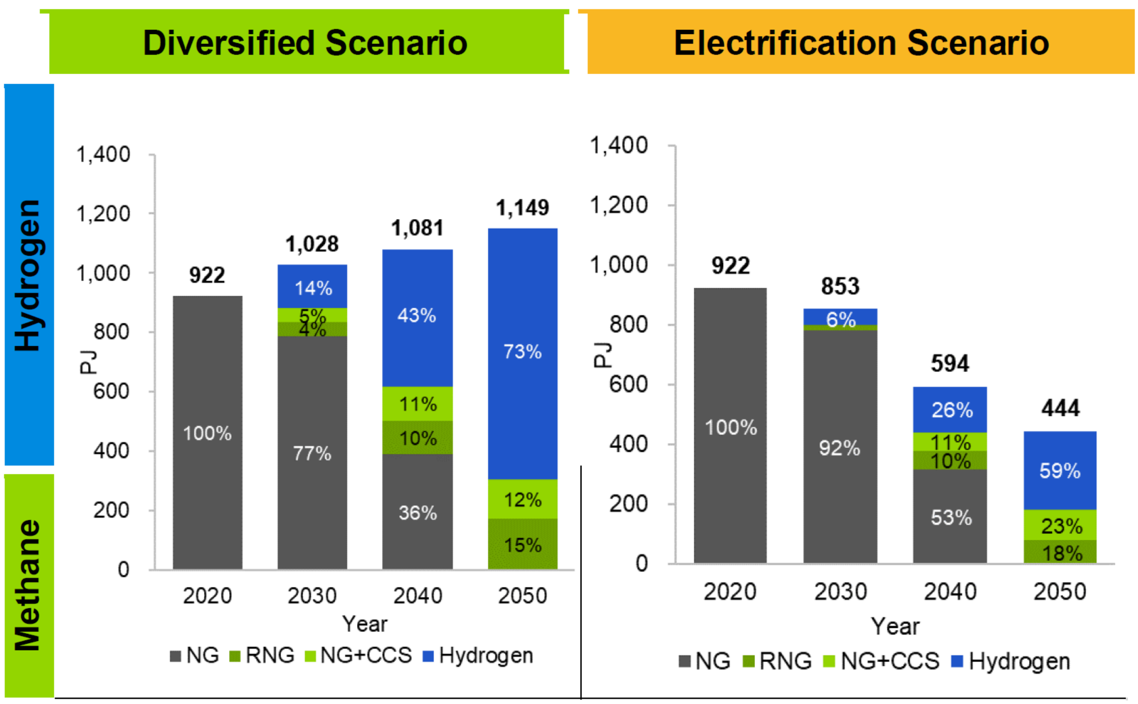
Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 26

Preamble:



Question(s):

a) Please complete the following table. Please provide a response on a best-efforts basis, making assumptions and stating caveats as necessary. Please provide all underlying sources, calculations, and assumptions. Please provide two copies – one in m3/yr and one in PJ/yr.

Consumption of Gaseous Fuels by Scenario and Year					
	2024	2025	2026	2027	2028
Diversified scenario					
Fossil gas					

Renewable natural gas					
Fossil gas with CCS					
Hydrogen derived from fossil gas (i.e. blue)					
Hydrogen derived from electrolysis (i.e. green)					
Electrification scenario					
Fossil gas					
Renewable natural gas					
Fossil gas with CCS					
Hydrogen derived from fossil gas (i.e. blue)					
Hydrogen derived from electrolysis (i.e. green)					

b) Please complete the following table. Please provide a response on a best-efforts basis, making assumptions and stating caveats as necessary. Please provide all underlying sources, calculations, and assumptions. Please provide two copies – one in m3/yr and one in PJ/yr.

Consumption of Gaseous Fuels by Scenario and Decade				
	2020	2030	2040	2050
Diversified scenario				
Fossil gas				
Renewable natural gas				
Fossil gas with CCS				
Hydrogen derived from fossil gas (i.e. blue)				
Hydrogen derived from electrolysis (i.e. green)				
Electrification scenario				
Fossil gas				
Renewable natural gas				
Fossil gas with CCS				
Hydrogen derived from fossil gas (i.e. blue)				
Hydrogen derived from electrolysis (i.e. green)				

c) This question is for Enbridge: Please complete the following table. Please provide a response on a best-efforts basis, making assumptions and stating caveats as necessary. Please provide all underlying sources, calculations, and assumptions. Please provide two copies – one in m3/yr and one in PJ/y.

Forecast Consumption of Gaseous Fuels per Enbridge Application					
	2024	2025	2026	2027	2028
Fossil gas					
Renewable natural gas					
Fossil gas with CCS					

Hydrogen derived from fossil gas (i.e. blue)					
Hydrogen derived from electrolysis (i.e. green)					

Response:

a) The following response was provided by Guidehouse Canada Ltd.:

Guidehouse declines to provide the requested table because the *Pathways to Net Zero Emissions for Ontario* Study modelled gaseous fuel consumption on a decade basis and not for the individual years specified in the requested table.

b) The following response was provided by Guidehouse Canada Ltd.:

Please see tables below.

Table 1 Consumption of Gaseous Fuels by Scenario and Decade (PJ/yr)					
	2020	2030	2040	2050	
Diversified scenario					
Fossil gas	922	772	414	0	/u
Renewable natural gas	0	44	91	170	/u
Fossil gas with CCS	0	48	114	134	/u
Hydrogen derived from fossil gas (i.e. blue)	0	144	288	305	/u
Hydrogen derived from electrolysis (i.e. green)	0	0	178	539	/u
Electrification scenario					
Fossil gas	922	78 7	314	0	/u
Renewable natural gas	0	0	59	72	/u
Fossil gas with CCS	0	0	64	103	/u
Hydrogen derived from fossil gas (i.e. blue)	0	55	151	149	/u
Hydrogen derived from electrolysis (i.e. green)	0	0	0	104	/u

Table 2
Consumption of Gaseous Fuels by Scenario and Decade (million m3/yr)

	2020	2030	2040	2050	
Diversified scenario					
Fossil gas	23,726	19,884v	10,654	0	/u
Renewable natural gas	0	1,134	2,340	4,375	/u
Fossil gas with CCS	0	1,226	2,939	3,450	/u
Hydrogen derived from fossil gas (i.e. blue)	0	11,908	23,822	25,169	/u
Hydrogen derived from electrolysis (i.e. green)	0	0	14,708	44,544	/u
Electrification scenario					
Fossil gas	23,726	20,251	8,095	0	/u
Renewable natural gas	0	0	1,511	1,855	/u
Fossil gas with CCS	0	0	1,649	2,653	/u
Hydrogen derived from fossil gas (i.e. blue)	0	4,534	12,483	12,328	/u
Hydrogen derived from electrolysis (i.e. green)	0	0	0	8,603	/u

c) Enbridge Gas declines to provide forecasted amount for RNG. This issue will be addressed in Phase 2 of the proceeding in accordance with the OEB’s Decision on Issues List dated January 27, 2023.

Enbridge Gas declines to provide forecasts for demand associated with natural gas with CCS and blue hydrogen as forecasts for these low carbon alternatives cannot be reliably estimated at this time, pending the development of further government regulations required to permit these activities within Ontario.

Please see Tables 3 and 4 below for the forecasted amount of gas demand for the 2024 to 2028 period, presented in millions m3/yr and PJ/year respectively. The forecasted volumes for natural gas in line 1 of the tables below represent the general service annual volume forecast as provided in the response to Exhibit I.1.10-STAFF-31 Attachment 1, Table 1 and the throughput volume forecast for the distribution contract market sales and T-service, as provided in the response to Exhibit I.1.10-STAFF-30, Attachment 1. The forecast for hydrogen in line 2 of the tables below reflects the maximum blend percentage of 2 percent by volume for the current area served by the Low Carbon Energy Project Phase (LCEP) Phase 1. The forecast builds on the year 1 actual hydrogen consumption in LCEP Phase 1, but may not fully represent future volumes. The forecast is subject to variability in gas flow in the system where blending is occurring at a rate between 0 to 2 percent and from variability in the hydrogen plant operations. Enbridge Gas is unable to estimate the impacts to the forecast due to LCEP Phase 2 as the blending rate has yet to be established for LCEP Phase 2.

Table 3
Forecast Consumption of Gaseous Fuels per Enbridge Application (millions m3/yr)

Line No.		2024	2025	2026	2027	2028
1	Combined General Service and Contract Volume forecast	27,922.9	28,140.7	28,963.0	28,963.3	28,942.6
2	Hydrogen derived from electrolysis (i.e. green)	0.18	0.18	0.18	0.18	0.18

Table 4
Forecast Consumption of Gaseous Fuels per Enbridge Application (PJ/yr)

Line No.		2024	2025	2026	2027	2028
1	Combined General Service and Contract Volume forecast	1091.2	1099.7	1131.9	1131.9	1131.1
2	Hydrogen derived from electrolysis (i.e. green)	0.0023	0.0023	0.0023	0.0023	0.0023

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

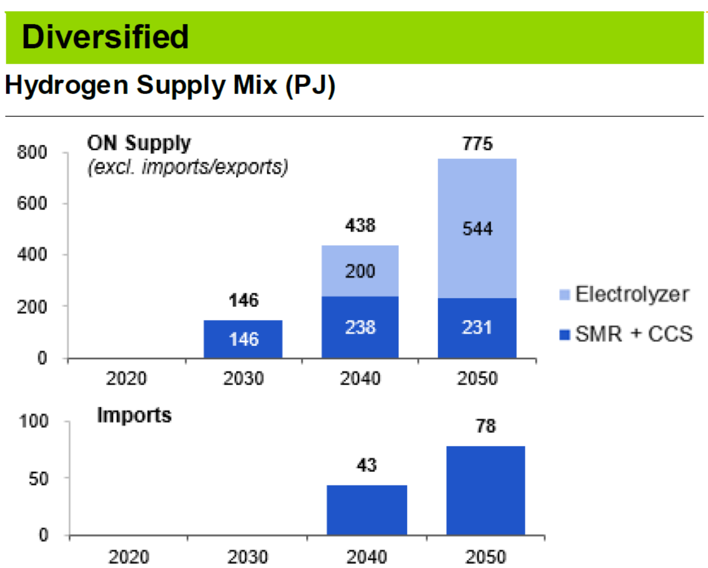
Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 40; CSA Statement on Hydrogen Blending

Preamble:

The following figure appears at page 40 of the Guidehouse report.



The Canadian Standards Organization Statement on Hydrogen Blending reads as follows:

Use of hydrogen and natural gas mixtures in products certified for natural gas in Canada and the US

It has come to our attention that some natural gas utilities in North America have begun to blend, or are planning to blend, hydrogen with natural gas for residential and industrial applications. In the interest of public safety, we are compelled to remind our customers and other stakeholders of the following:

- At present, there are no accepted standards in Canada or the US for fuel burning products using mixtures of natural gas and hydrogen, for either residential or industrial applications

- In the absence of accepted standards, CSA Group does not currently offer certification programs for products and appliances that burn a mixture of natural gas and hydrogen

- CSA Group's current certification programs only apply to products that burn natural gas in accordance with existing accepted standards

- CSA certification of a product is void when it is used outside the parameters of the applicable standards – which would include the use of fuels other than natural gas, such as a mixture of natural gas and hydrogen

CSA Group has been following developments related to the potential use of hydrogen and hydrogen fuel blends in fuel-burning products for many years, and we are currently involved in several research initiatives to study these alternative fuels and their implications. Technical committees within our standards development organization are evaluating potential amendments of the current fuel burning standards to include hydrogen and natural gas mixtures. This evaluation is ongoing and involves a thorough review of supporting evidence.

Research and testing are vital to ensuring that any modifications to the current standards for fuel-burning appliances achieve their core purpose – enabling the safe deployment of products in society. While we are excited by the potential role hydrogen could play in reducing carbon emissions, we feel it is vital that the necessary research and standards development take place before hydrogen-blended fuels are used in products certified solely for natural gas.

It is our hope that, until appropriate standards and certification programs are in place, gas utilities and other suppliers of natural gas will abstain from blending hydrogen with natural gas for use with products only certified for natural gas. We urge utilities, regulatory authorities, certification bodies, and manufacturers of gas appliances to work together to ensure that the use of any mixture of hydrogen and natural gas in natural gas products take place only after the ongoing research is complete, the standards are amended, and products can be certified to the amended standards.

<u>Question(s)</u>:

a) The CSA states as follows: "CSA certification of a product is void when it is used outside the parameters of the applicable standards – which would include the use of fuels other than natural gas, such as a mixture of natural gas and hydrogen." Does Enbridge agree? If not, please explain.

b) In light of the above, please confirm that the CSA certification of the gas equipment in all homes served by Enbridge's hydrogen blending project is void. If not, please explain.

c) Is Enbridge offering compensation to customers whose gas equipment no longer has valid CSA certification due to Enbridge's hydrogen blending pilot? If not, why not?

d) The CSA states as follows: "We urge utilities, regulatory authorities, certification bodies, and manufacturers of gas appliances to work together to ensure that the use of any mixture of hydrogen and natural gas in natural gas products take place only after the ongoing research is complete, the standards are amended, and products can be certified to the amended standards." Will Enbridge abide by this request from the CSA? If not, why not?

e) When did Enbridge first become aware of this CSA statement?

f) When Enbridge first became aware of this CSA statement, did it consider halting its hydrogen blending pilot, for example, on the basis that it would be voiding the CSA certification of its customers' gas equipment?

g) What are the consequences for a consumer with gas equipment that without valid CSA certification?

<u>Response:</u>

a-c,g) Enbridge Gas recognizes that the constituents and resulting quality of 'natural gas' are inherently variable due to the interconnected nature of the North American gas grid which draws on multiple sources of production and imports. Under the *Technical Standards and Safety Act, 2000, S.O. 2000, c.16 (TSSA), Ontario Regulation 210/01, Oil and Gas Pipeline Systems,* the term "gas" 'means any gas or mixture of gases suitable for domestic or industrial fuel that is conveyed to the user through a pipeline.' Similarly, the *OEB's* definition of "gas" 'means natural gas, substitute natural gas, synthetic gas, manufactured gas, propane-air gas or any mixture of any of them.'[1] As such, small amounts of hydrogen may be part of the natural gas mixture and continue to fall within the parameters of CSA's test gas for appliance certification.

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[1] Ontario Energy Board Act, 1998, S.O. 1998, c.15, Sched. B (OEB). https://www.ontario.ca/laws/statute/98o15/v49

In the OEB's approval of Enbridge Gas's hydrogen blending project the OEB found that the TSSA's review of Enbridge Gas's risk assessment led to its conclusion that at the low levels of hydrogen proposed in the pilot, there is no significant risk to the distribution system, Enbridge Gas's customers or their equipment.[2] To date, Enbridge Gas has not had any customer reports of any component or appliance failure since the inception of the project. Enbridge Gas also indicated in that proceeding:

> *Enbridge Gas's research concludes that the maximum 2% hydrogen blend by volume does not cause a material change to the combustion parameters of the gas that has been distributed within the BGA. Enbridge Gas research indicates that the risk associated with hydrogen blending in the BGA is acceptable. Any instance of appliance failure or failure of appliance components would more likely be attributable to wear and tear or lack of maintenance. In the unlikely event that it is determined that the hydrogen content of the blended gas delivered in the BGA caused the failure of components or appliances the Company would compensate the affected customer.*[3]

Enbridge Gas cannot comment on the voidance of a CSA certification. The confirmation of whether appliances are void of CSA certification would be determined by CSA. The consequences to a consumer would be determined by the appliance manufacturer.

d- f) Enbridge Gas first became aware of this CSA statement on November 22, 2022. Enbridge Gas continues to operate its hydrogen blending pilot as approved by the OEB and its technical regulator, the Technical Standards and Safety Authority (TSSA). Enbridge Gas has also been working with the CSA 's Technical Committee team, on developing standards for higher levels of hydrogen blending.

There are ongoing discussions with CSA Technical Committee team that Enbridge Gas is part of, and that has representation from gas utilities, regulatory authorities, certification bodies, manufacturers of gas appliances, and research organizations. To date discussions have included; perspectives of CSA position on their November 22 statement, and working together to find ways for the CSA to evolve their position. Enbridge Gas has shared research and testing data for both low level blending and higher levels of hydrogen blending. Enbridge Gas is advancing the position that low levels of hydrogen up to 5% results in gas that essentially acts as natural gas, recognizing that the existing natural gas composition is inherently variable. Enbridge Gas does not believe that new standards are required for low level blending of hydrogen, but does agree that hydrogen blends above 5% may require updated standards, including different standards for blending at higher levels of 20-30% (and

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[2] EB-2019-0294, Decision and Order, October 29, 2020, p.8.
[3] EB-2019-0294, Exhibit I.FRPO.8

for 100% hydrogen). Enbridge Gas is committed to working with the CSA to support the development of updated standards.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

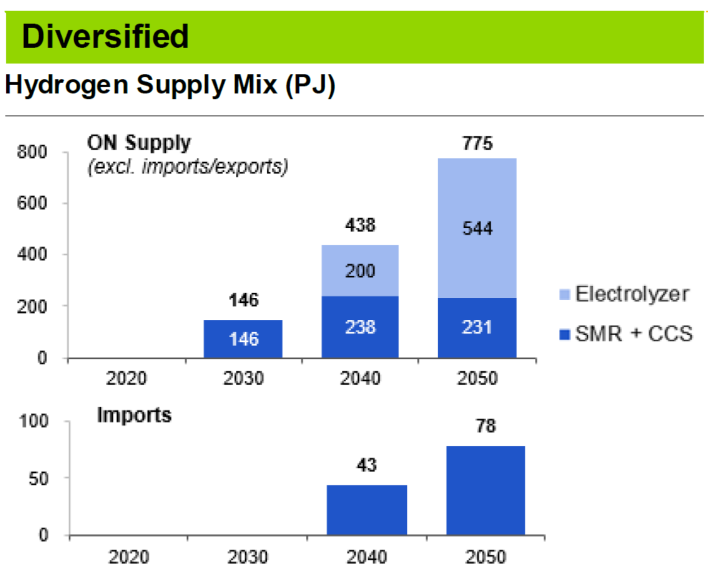
Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 40

Preamble:

The following figure appears at page 40 of the Guidehouse report.



Question(s):

a) Please complete the following table with details regarding the use of hydrogen under the two scenarios:

Hydrogen Consumption by Scenario				
	2020	2030	2040	2050
Diversified scenario				
Hydrogen consumption (m3/yr)				
Hydrogen consumption at 100% H2 concentration (m3/yr)				

Hydrogen consumption in a hydrogen/methane blend (m3/yr)				
Maximum hydrogen concentration (%, by volume)				
Maximum hydrogen concentration (%, by energy value)				
Electrification scenario				
Hydrogen consumption (m3/yr)				
Hydrogen consumption at 100% H2 concentration (m3/yr)				
Hydrogen consumption in a hydrogen/methane blend (m3/yr)				
Maximum hydrogen concentration (%, by volume)				
Maximum hydrogen concentration (%, by energy value)				

b) Please provide a copy of the above table with the m3/yr figures replaced by PJ/yr.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Please see Table 1, with hydrogen consumption in terms of billion m3 per year.

Table 1
Hydrogen Consumption by Scenario

	2020	2030	2040	2050	
Diversified scenario					
Hydrogen consumption (billion m3/yr)	0	11.9	38.5	69.7	/u
Hydrogen consumption at 100% H2 concentration (billion m3/yr)	0	11.9	35.5	68.4	
Hydrogen consumption in a hydrogen/methane blend (billion m3/yr)	0	0	3	1.4	
Maximum hydrogen concentration (%, by volume)	0.0%	0.0%	19.2%	20.0%	
Maximum hydrogen concentration (%, by energy value)	0.0%	0.0%	6.0%	6.3%	
Electrification scenario					
Hydrogen consumption (billion m3/yr)	0	4.5	12.5	20.9	/u
Hydrogen consumption at 100% H2 concentration (billion m3/yr)	0	4.5	11.1	20	/u

Table 1 (Continued)
Hydrogen Consumption by Scenario

	2020	2030	2040	2050
Hydrogen consumption in a hydrogen/methane blend (billion m3/yr)	0	0	1.4	1
Maximum hydrogen concentration (%, by volume)	0.0%	0.0%	6.4%	20.0%
Maximum hydrogen concentration (%, by energy value)	0.0%	0.0%	2.0%	6.3%

b) Please see Table 2, with hydrogen consumption in terms of PJ per year.

Table 2
Hydrogen Consumption by Scenario

	2020	2030	2040	2050	
Diversified scenario					
Hydrogen consumption (PJ/yr)	0.0	144.2	466.5	843.9	/u
Hydrogen consumption at 100% H2 concentration (PJ/yr)	0.0	144.2	429.9	827.5	/u
Hydrogen consumption in a hydrogen/methane blend (PJ/yr)	0.0	0.0	36.6	16.4	/u
Maximum hydrogen concentration (%, by volume)	0.0%	0.0%	19.2%	20.0%	
Maximum hydrogen concentration (%, by energy value)	0.0%	0.0%	6.0%	6.3%	
Electrification scenario					
Hydrogen consumption (PJ/yr)	0.0	54.9	151.1	253.4	/u
Hydrogen consumption at 100% H2 concentration (PJ/yr)	0.0	54.9	134.5	241.7	/u
Hydrogen consumption in a hydrogen/methane blend (PJ/yr)	0.0	0.0	16.6	11.7	/u
Maximum hydrogen concentration (%, by volume)	0.0%	0.0%	6.4%	20.0%	
Maximum hydrogen concentration (%, by energy value)	0.0%	0.0%	2.0%	6.3%	

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

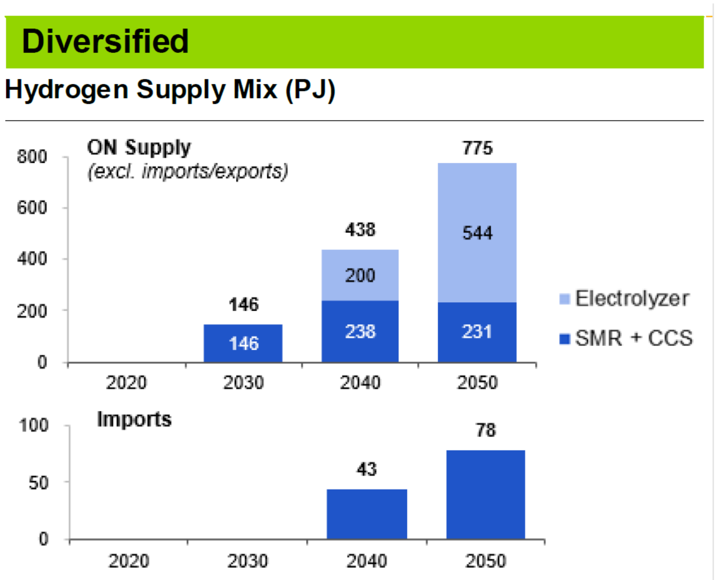
Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 40

Preamble:

The following figure appears at page 40 of the Guidehouse report.



Question(s):

a) What percentage of hydrogen blending has been confirmed to be safe? Please explain and provide references. Please provide the response both in terms of percent by volume and percent by energy value.

b) The California Public Utilities Commission concluded as follows:

> "Relative to injecting and blending hydrogen into the natural gas pipeline, leaks and losses of hydrogen gas are two important considerations. Leaks are of high importance for safety reasons particularly in confined spaces, while losses are more relevant to storage and economics. Leaks in the distribution natural gas system, comprised of plastic pipelines are expected to occur primarily by

hydrogen permeation, while the majority of leaks in the transmission system and distribution system comprised of metal pipelines are expected to occur through cracks, joints, seals, or threads [2]. The findings of the experimental work conducted by this project on controlled leaks through orifices, suggest that volumetric gas blend leak flow rate increases with increase in concentration of hydrogen gas in the blend …

Based on a recently published report, there is literature available for the lower blending percentage (1-2% per volume). Beyond 2%, the literature starts to show gaps in areas such as ‘inspection and maintenance’ and ‘underground gas storage’.”[1]

Does Guidehouse agree that the safety of hydrogen blending at percentages beyond 2% has not yet been conclusively established due to remaining gaps in the literature?

c) The California Public Utilities Commission concluded as follows:

Under the assumption of viscous turbulent flow for gas leaks in the natural gas pipeline system, originating from joints, threads, cracks, and pinhole defects, gas blends of hydrogen and methane would leak at a higher volumetric flow rates compared to pure methane, under the same conditions. The increase of flow rate is inversely proportional to the square root of the specific gravity of the hydrogen/methane gas blend. Thus for a gas blend containing 10% hydrogen the expected increase in flow rate is 5% compared to pure methane, while for 20% hydrogen gas blend the increase in leak flow rate is 10%.[2]

Does Guidehouse or Enbridge have any reason to disagree with that conclusion?

d) The California Public Utilities Commission concluded as follows:

The lower energy content of hydrogen gas compared to methane, means that a volume of hydrogen more than three times that of methane is necessary to deliver the same amount of energy. Therefore, without any changes in the natural gas transmission and distribution pipeline system, larger operating pressures may be required with hydrogen- methane gas blends to deliver the same amount of energy comparable to pure methane. Increasing operating pressure would result in increased leak flow rates. Thus any changes to

[1] The California Public Utilities Commission, Final Report, *Hydrogen Blending Impacts Study*, Prepared by: University of California, Riverside, July 18, 2022, p. 107 (link).
[2] The California Public Utilities Commission, Final Report, *Hydrogen Blending Impacts Study*, Prepared by: University of California, Riverside, July 18, 2022, p. 37 (link).

operating gas pressure should consider gas leak rates, among other factors, such as integrity of the system.[3]

Does Guidehouse or Enbridge have any reason to disagree with that conclusion?

e) The California Public Utilities Commission concluded as follows:

> Hydrogen gas has significantly broader flammability range, much lower ignition energy, and higher flame velocity compared to natural gas.[4]

Do Guidehouse and Enbridge agree? If not, why not.

f) Please provide a table comparing the flammability range, ignition energy, and flame velocity of hydrogen and methane.

Response:

a-b) No two gas distribution systems are the same. Hydrogen blending requires that a case-by-case engineering assessment be conducted to ensure system compatibility with hydrogen in consideration of the unique circumstances of each blended gas area. Reports[5,6] issued by the Canadian Gas Association (CGA) and American Gas Association (AGA) as well as California Public Utilities Commission (CPUC) suggest that hydrogen blending may be possible at varying concentrations, including at concentrations above 2%. The CPUC concludes the following: "Providing that the hydrogen blend is homogeneous, it was reported that the addition of 10% hydrogen to a typical natural gas blend, does not impose significant impacts to the gas quality, materials, network capacity, safety or risk aspects"[7]

Enbridge Gas's proposed Hydrogen Blending Grid Study, amongst other objectives, seeks to identify safe limits for hydrogen as it applies to Enbridge Gas's systems and customers. Please see Exhibit 4, Tab 2, Schedule 6, pages 16 to 17.

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[3] The California Public Utilities Commission, Final Report, *Hydrogen Blending Impacts Study*, Prepared by: University of California, Riverside, July 18, 2022, p. 37 (link).
[4] The California Public Utilities Commission, Final Report, Hydrogen Blending Impacts Study, Prepared by: University of California, Riverside, July 18, 2022, p. 37 (link).
[5] EB-2019-0294, Exhibit I.H2GO.1, Attachment 1.
[6] Enabling Higher-Hydrogen Blending in the Natural Gas Distribution System, October 2022, https://www.cga.ca/wp-content/uploads/2022/10/CGA-Hydrogen-Blending-Greater-than-5.pdf
[7] The California Public Utilities Commission, Final Report, Hydrogen Blending Impacts Study, July 18, 2022, p.108. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse has not independently evaluated the safety of hydrogen blending in natural gas pipelines. In developing scenario assumptions for the P2NZ Study, Guidehouse relied on secondary research to determine blending limits for hydrogen. The CPUC study referenced in the question notes multiple successful ongoing efforts to blend hydrogen at levels about 5% by volume, including successful long-term blending at levels of 10-12% by volume by Hawaii Gas, and successful pilots with 20% blending by volume in France, the Netherlands, and England.[8] Other studies also support assumptions of gradually higher blend levels, including a 2019 report from French gas infrastructure operators, which cites a 20% by volume blending threshold as the level of hydrogen blending above which significant investment will be needed.[9] Additional studies of hydrogen blending are underway in the UK, including National Grid's FutureGrid project that will study whether the National Transmission System will be able to tolerate higher concentrations of hydrogen, up to 100%.[10] The US National Renewable Energy Laboratory published a review of active blending projects in gas transmission networks.[11] For the purposes of the P2NZ Study, Guidehouse assumed that blending hydrogen in natural gas supplies at rates of 20% by volume was a reasonable blending limit for the report scenarios.

c) Enbridge Gas is not privy to the efficacy of the calculations used to arrive at the relations presented in the CPUC report; however, Enbridge Gas recognizes that engineering assessments for pipeline systems are important to identify sources of potential leaks and modifications to reduce and/or eliminate them. Within the CPUC report, other studies referenced indicate identical leak rates for hydrogen and methane under some conditions. One must read beyond the portion of text provided in the question to see the full conclusion of the CPUC which states:

> Despite the increase of total volumetric gas flow rate with the blending of hydrogen with natural gas, the overall methane emissions would decrease, while the overall energy loss due to leaks would remain relatively unchanged due to the lower energy density of hydrogen compared to methane.

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[8] California Public Utilities Commission (2022). "Hydrogen Blending Impacts Study." p.4-5. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF

[9] GRTgaz et. al (2019). "Technical and economic conditions for injecting hydrogen into natural gas networks". p.12. Available at: https://www.storengy.fr/sites/default/files/mediateque/pdf/2019-11/2019-06-28%20Mesure%207%20-%20Rapport%202_final_EUK.pdf

[10] National Grid (2022). "FutureGrid." Available at: https://www.nationalgas.com/insight-and-innovation/transmission-innovation/futuregrid

[11] US NREL (2022). "Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology." Table 7. Available at: https://www.nrel.gov/docs/fy23osti/81704.pdf

> Even if majority of hydrogen-natural gas blend leaks can be attributed to permeation or viscous flow, which both result in larger volumetric flow rates with increased concentration of hydrogen in the gas blend, other leak mechanisms should be considered.[12]

A study by the European Commission Joint Research Union (JRC), reported on a study by Sandia National Laboratories which, points out in its findings that:

> The volumetric flowrate of hydrogen is higher than for methane at fixed pressure. In contrast, mass and energy flow rate of methane are higher than hydrogen at fixed pressure. Figure 22 b) shows that volumetric flow rate of hydrogen, [depicted in blue], is about three times that of the methane for an equivalent leak. However, the mass flow of hydrogen is significantly lower. This means that the leak rate is substantially lower on a mass basis for hydrogen due to the lower density of hydrogen vs methane.[13]

Leaks can exhibit a range of turbulent, laminar or mixed-flow regimes. A component of Enbridge Gas's Grid Study is for the proposed Grid Study's Engineering assessment to identify potential impact to leak rates in pipeline systems with a hydrogen-blended gas and recommend any necessary modifications.

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse declines to answer these questions, as Guidehouse has not independently studied the leak flow rates of hydrogen-blended natural gas.

d) Natural gas pipeline systems in Ontario are regulated by the Technical Standards and Safety Authority (TSSA) who has adopted the CAN/CSA Z662 Oil and Gas Pipeline Systems standard. Under this standard, a change in service fluid, which would include the addition of blended hydrogen, requires that an engineering assessment be conducted. The assessment must consider a multitude of factors including the potential for gas leaks, impact on system integrity and management systems, and risk assessments. Please also see response at Exhibit I.1.4.2-ED-127 parts b-e).

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse declines to answer these questions, as Guidehouse has not independently studied the leak flow rates of hydrogen-blended natural gas.

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[12] The California Public Utilities Commission, Final Report, Hydrogen Blending Impacts Study, July 18, 2022, p.37. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF
[13] Hydrogen emissions from a hydrogen economy and their potential global warming, p.31, https://op.europa.eu/en/publication-detail/-/publication/918b0980-21c7-11ed-8fa0-01aa75ed71a1/language-en

e) Enbridge Gas agrees that pure hydrogen has different thermodynamic properties compared to pure methane; however, it is important to note that low blends of hydrogen in natural gas do not differ significantly in behaviour compared to pure natural gas. This is shown in response at part f) and c).

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse declines to answer these questions, as Guidehouse has not independently studied the flammability ranges of hydrogen-blended natural gas.

f) It should be noted that natural gas may contain varying constituents that would affect its thermodynamic properties. In particular, flame velocity and combustion are dependent on numerous parameters such as fuel composition, fuel gas pressure, fuel-air ratio, combustion method, etc. Table 1 provides the following information from H2 Tools comparing pure hydrogen to pure methane in tabular form.

The following response was provided by Guidehouse Canada Ltd.:

Guidehouse declines to answer these questions, as Guidehouse has not independently studied the flammability ranges of hydrogen-blended natural gas.

Table 1
Comparison of Pure Hydrogen to Pure Methane[14]

Property	Units	Hydrogen	Methane
Chemical Formula		H_2	CH_4
Molecular Weight [a, b]		2.02	16.04
Density, NTP [3, a, c]	kg/m³	0.0838	0.668
	lb/ft³	0.00523	0.0417
Viscosity, NTP [3, a, b]	g/cm-sec	8.81 E-5	1.10 E-4
	lb/ft-sec	5.92 E-6	7.41 E-6
Normal Boiling Point [a, b]	°C	-253	-162
	°F	-423	-259
Vapor specific gravity, NTP [3, a, d]	air = 1	0.0696	0.555
Flash Point [b, d]	°C	<-253	-188
	°F	<-423	-306
Flammability Range in Air [c, b, d]	vol%	4.0 - 75.0	5.0 - 15.0
Auto ignition temperature [b, d]	°C	585	540
	°F	1085	1003
Maximum flame velocity in air [2, c]	m/s	2.83	0.45
	ft/s	9.28	1.48

Notes:

- Properties of the pure substance
- Properties of a range of commercial grades
- NTP = 20°C (68°F) and 1 atmosphere

[14] Hydrogen Tools. Comparative Properties of Hydrogen and Other Fuels. https://h2tools.org/hyarc/hydrogen-data/comparative-properties-hydrogen-and-other-fuels

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 43

Preamble:

These questions relate to the costing of the scenarios.

Question(s):

a) Please complete the following tables with the average and marginal cost assumptions underlying Guidehouse's analysis of the two scenarios:

Commodity, Transmission, and Distribution Cost Assumptions – Diversified Scenario				
	2020	2030	2040	2050
Electricity – Average Cost				
Energy cost ($/MWh)				
Capacity cost ($/MW)				
Transmission & distribution ($/MW)				
Electricity – Marginal Cost				
Energy ($/MWh)				
Capacity ($/MW)				
Transmission & distribution ($/MW)				
Fossil gas – Average Cost				
Commodity ($/PJ)				
Transmission & distribution ($/PJ/hr)				
Fossil gas – Marginal Cost				
Commodity ($/PJ)				
Transmission & distribution ($/PJ/hr)				
Fossil gas with CCS – Average Cost				
Commodity ($/PJ)				
CCS process ($/PJ)				
Transmission & distribution ($/PJ/hr)				
Fossil gas with CCS – Marginal Cost				
Commodity ($/PJ)				
CCS process ($/PJ)				

Transmission & distribution ($/PJ/hr)				
RNG – Average Cost				
Commodity ($/PJ)				
Transmission & distribution ($/PJ/hr)				
RNG – Marginal Cost				
Commodity ($/PJ)				
Transmission & distribution ($/PJ/hr)				
Green Hydrogen – Average Cost				
Commodity ($/PJ)[1]				
Transmission & distribution ($/PJ/hr)				
Green Hydrogen – Marginal Cost				
Commodity ($/PJ) [2]				
Transmission & distribution ($/PJ/hr)				
Blue Hydrogen – Average Cost				
Commodity ($/PJ)[3]				
Transmission & distribution ($/PJ/hr)				
Blue Hydrogen – Marginal Cost				
Commodity ($/PJ) [4]				
Transmission & distribution ($/PJ/hr)				

Commodity, Transmission, and Distribution Cost Assumptions – Electrified Scenario				
	2020	2030	2040	2050
Electricity – Average Cost				
Energy cost ($/MWh)				
Capacity cost ($/MW)				
Transmission & distribution ($/MW)				
Electricity – Marginal Cost				
Energy ($/MWh)				
Capacity ($/MW)				
Transmission & distribution ($/MW)				
Fossil gas – Average Cost				
Commodity ($/PJ)				
Transmission & distribution ($/PJ/hr)				
Fossil gas – Marginal Cost				
Commodity ($/PJ)				

[1] Including the electrolysis process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.
[2] Including the electrolysis process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.
[3] Including the SMR process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.
[4] Including the SMR process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.

Transmission & distribution ($/PJ/hr)				
Fossil gas with CCS – Average Cost				
Commodity ($/PJ)				
CCS process ($/PJ)				
Transmission & distribution ($/PJ/hr)				
Fossil gas with CCS – Marginal Cost				
Commodity ($/PJ)				
CCS process ($/PJ)				
Transmission & distribution ($/PJ/hr)				
RNG – Average Cost				
Commodity ($/PJ)				
Transmission & distribution ($/PJ/hr)				
RNG – Marginal Cost				
Commodity ($/PJ)				
Transmission & distribution ($/PJ/hr)				
Green Hydrogen – Average Cost				
Commodity ($/PJ)[5]				
Transmission & distribution ($/PJ/hr)				
Green Hydrogen – Marginal Cost				
Commodity ($/PJ) [6]				
Transmission & distribution ($/PJ/hr)				
Blue Hydrogen – Average Cost				
Commodity ($/PJ)[7]				
Transmission & distribution ($/PJ/hr)				
Blue Hydrogen – Marginal Cost				
Commodity ($/PJ) [8]				
Transmission & distribution ($/PJ/hr)				

b) Please complete the following tables with the annualized costs in the two scenarios and provide the response in a live excel spreadsheet. If we have missed any energy-related cost categories, please add those. If a cost is not included in the scenarios (or is only partially included), please indicate so and provide a best estimate of the value.

[5] Including the electrolysis process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.
[6] Including the electrolysis process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.
[7] Including the SMR process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.
[8] Including the SMR process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.

Annualized Cost Figures – Diversified Scenario				
	2020	2030	2040	2050
Electricity				
Annual energy demand (MWh)				
Annual avg. energy price ($/MWh)				
Annual energy cost ($)				
Annual capacity demand (MW)				
Capacity cost ($/MW, annualized)				
Annual capacity cost ($)				
Transmission & distribution cost ($/MW, annualized)				
Annual transmission and distribution cost ($, annualized)				
Annual electricity costs ($)				
Fossil gas				
Annual demand (PJ)				
Annual avg. commodity price ($/PJ)				
Annual commodity cost ($)				
Annual capacity demand (PJ/hr)				
Transmission & distribution cost ($/PJ/hr, annualized)				
Annual transmission and distribution costs ($, annualized)				
Annual fossil gas costs ($)				
Fossil gas with CCS				
Annual demand (PJ)				
Annual avg. commodity price ($/PJ)				
Annual commodity cost ($)				
Annual avg. CCS costs ($/PJ)				
Annual CCS costs ($)				
Annual capacity demand (PJ/hr)				
Transmission & distribution cost ($/PJ/hr, annualized)				
Annual transmission and distribution costs ($, annualized)				
Annual fossil gas with CCS costs ($)				
RNG				
Annual demand (PJ)				
Annual avg. commodity price ($/PJ)				
Annual commodity cost ($)				
Annual capacity demand (PJ/hr)				
Transmission & distribution cost ($/PJ/hr, annualized)				

Annual transmission and distribution costs ($, annualized)				
Annual RNG costs ($)				
Green Hydrogen				
Annual demand (PJ)				
Annual avg. commodity price ($/PJ) [9]				
Annual commodity cost ($)				
Annual capacity demand (PJ/hr)				
Transmission & distribution cost ($/PJ/hr, annualized)				
Annual transmission and distribution costs ($, annualized)				
Annual green hydrogen costs ($)				
Blue Hydrogen				
Annual demand (PJ)				
Annual avg. commodity price ($/PJ)[10]				
Annual commodity cost ($)				
Annual capacity demand (PJ/hr)				
Transmission & distribution cost ($/PJ/hr, annualized)				
Annual transmission and distribution costs ($, annualized)				
Annual blue hydrogen costs ($)				

Annualized Cost Figures – Electrified Scenario				
	2020	2030	2040	2050
Electricity				
Annual energy demand (MWh)				
Annual avg. energy price ($/MWh)				
Annual energy cost ($)				
Annual capacity demand (MW)				
Capacity cost ($/MW, annualized)				
Annual capacity cost ($)				
Transmission & distribution cost ($/MW, annualized)				
Annual transmission and distribution cost ($, annualized)				
Annual electricity costs ($)				

[9] Including the electrolysis process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.
[10] Including the SMR process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.

Fossil gas				
Annual demand (PJ)				
Annual avg. commodity price ($/PJ)				
Annual commodity cost ($)				
Annual capacity demand (PJ/hr)				
Transmission & distribution cost ($/PJ/hr, annualized)				
Annual transmission and distribution costs ($, annualized)				
Annual fossil gas costs ($)				
Fossil gas with CCS				
Annual demand (PJ)				
Annual avg. commodity price ($/PJ)				
Annual commodity cost ($)				
Annual avg. CCS costs ($/PJ)				
Annual CCS costs ($)				
Annual capacity demand (PJ/hr)				
Transmission & distribution cost ($/PJ/hr, annualized)				
Annual transmission and distribution costs ($, annualized)				
Annual fossil gas with CCS costs ($)				
RNG				
Annual demand (PJ)				
Annual avg. commodity price ($/PJ)				
Annual commodity cost ($)				
Annual capacity demand (PJ/hr)				
Transmission & distribution cost ($/PJ/hr, annualized)				
Annual transmission and distribution costs ($, annualized)				
Annual RNG costs ($)				
Green Hydrogen				
Annual demand (PJ)				
Annual avg. commodity price ($/PJ) [11]				
Annual commodity cost ($)				
Annual capacity demand (PJ/hr)				
Transmission & distribution cost ($/PJ/hr, annualized)				
Annual transmission and distribution costs ($, annualized)				

[11] Including the electrolysis process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.

Annual green hydrogen costs ($)				
Blue Hydrogen				
Annual demand (PJ)				
Annual avg. commodity price ($/PJ)[12]				
Annual commodity cost ($)				
Annual capacity demand (PJ/hr)				
Transmission & distribution cost ($/PJ/hr, annualized)				
Annual transmission and distribution costs ($, annualized)				
Annual blue hydrogen costs ($)				

c) Please describe how each of the figures in (b) was derived, including any relevant sources.

Response:

The following response was provided by Guidehouse Canada Ltd.:

The purpose of the P2NZ analysis was to forecast the demand for different energy types based on two plausible scenarios to achieve net zero emissions in 2050, and to estimate the total energy system costs that would be required to transition Ontario's energy system to supply the energy demand forecast for each scenario. The P2NZ analysis was conducted to estimate total system costs, and not to forecast energy prices, commodity costs, or average or marginal costs of production, transmission, and distribution.

Guidehouse declines to complete the tables as specified in a) and b) because few of the data points requested are available as outputs from the P2NZ analysis. Guidehouse is unable to provide per-unit energy cost estimates for electricity, methane, or hydrogen because Guidehouse's approach to modeling did not forecast or determine the average or marginal costs of different energy sources in Ontario. Similarly, Guidehouse is unable to provide commodity costs, because Guidehouse's approach to cost modeling did not determine commodity costs for RNG or hydrogen on a $/PJ basis. Instead, Guidehouse accounted for the cost of these fuels by (1) determining the required production capacity by decade, (2) estimating the capital costs of developing new production capacity, and (3) estimating the fixed and variable O&M costs of using this capacity to produce RNG and hydrogen.

The sections below highlight the requested data points that are available from the study.

[12] Including the SMR process, CCS process, and transportation to Ontario if that is applicable and not included in the transmission and distribution row below.

a) For natural gas prices, Table A-1 of the P2NZ Report provides the natural gas price forecast used in the P2NZ analysis.

   Table A-11 of the P2NZ Report describes the capital and O&M costs assumed for RNG and hydrogen production technologies in 2030, 2040, and 2050.

   The P2NZ analysis estimated the total cost of intraregional and interregional gas and electric transmission but did not calculate average or marginal T&D costs. Please see response at Exhibit I.1.10-GEC-20, Attachment 1 for details on interregional transmission cost estimates.

b) For a breakdown of annual energy demand by energy source and by decade for the Diversified and Electrification scenarios, please see response at Exhibit I.1.10-SEC-26 Attachment 1, page 2."

   Projected peak demand for methane fuel and hydrogen fuel in aggregate are provided in P2NZ report Figure 15, subheading "Gas Energy Peak Demand (TJ/hour)." However, the LCP model does not break out capacity demand for methane into natural gas and RNG, nor does it provide capacity demand for hydrogen disaggregated to blue hydrogen and green hydrogen.

c) Guidehouse did not compile a single repository spreadsheet of inputs. Please see Appendix A of the P2NZ Report for a detailed description of input data used and data sources referenced in the P2NZ Study.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

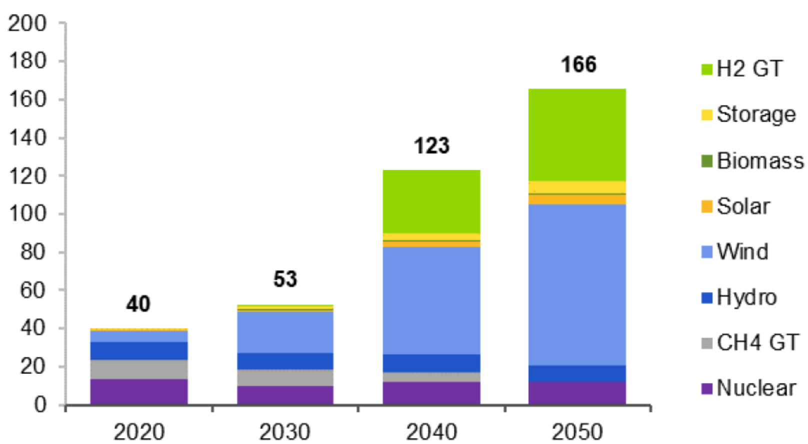
Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 36

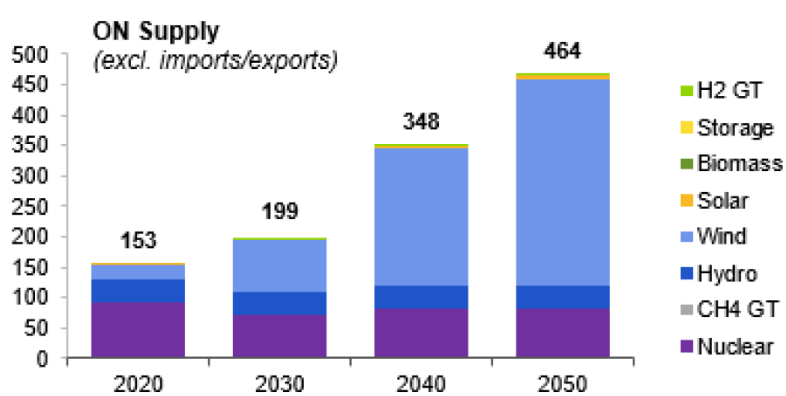
Preamble:

Electrification

Electricity Supply Capacity (GW)



Electricity Supply Mix (TWh)



Question(s):

a) Please complete the following table detailing the cost of the electricity supply resources listed above. If they differ between each, please complete one table per scenario.

Cost of Electricity Supply Resources				
	2020	2030	2040	2050
Resource 1 … n				
LUEC ($/MWh)				
Energy ($/MWh)				
Capacity ($/MW, levelized)				
…				

b) Guidehouse includes a large amount of hydrogen generation capacity starting in 2040. Please explain this? Is that because Guidehouse assumes hydrogen generation to be cheaper than all other alternatives? If yes, please explain, including via a comparison with the cost of storage.

c) Why did Guidehouse not include demand response as a resource?

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) The Guidehouse analysis did not calculate levelized unit electricity costs (LUEC) for different electric generating resources. Instead, the Low Carbon Pathways model accounts for the capital cost of installing the resource (the cost of new resource, or CONE) and the fixed and variable operations & maintenance costs (FOM and VOM) associated with using each generation resource. Table A-11 of the *Pathways to Net Zero Emissions for Ontario* Study contains the CONE, FOM, and VOM assumptions for all of the modeled resources. The CONE, FOM, and VOM assumptions are the same for the core Electrification and Diversified scenarios.

b) In the *Pathways to Net Zero Emissions for Ontario* Study, the Electrification scenario assumes that new hydrogen-fired gas turbine generators will be installed between 2030 and 2040 to serve as a peaking resource to deal with the sharp increase in electric system peak demand resulting from the electrification of space heating and other end uses assumed in that scenario. Hydrogen gas turbines have advantages compared to other available peaking resources (e.g., batteries, pumped hydro, and natural gas turbines), in that they produce zero carbon emissions, they have long duration and high capacity storage options, and they can be installed in a variety of topographies.

c) At the time of the analysis, the Low Carbon Pathways model did not include explicit modeling of demand response measures as a feature. Guidehouse implicitly account for the impact of demand response in the transportation sector when developing the demand forecasts. Guidehouse estimated that the managed charging of electric vehicles will be an impactful demand response measure that will shape the hourly electric load profile of the transportation sector. To implicitly account for the impact of demand response, the analysis used separate electric load shapes for the buildings and transportation sectors that do not have coincident peaks.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 36

Question(s):

a) Please provide a table showing the potential energy and capacity from the following incremental non-emitting resources.

Electricity Resource Potential – Energy and Capacity				
	2020	2030	2040	2050
Wind				
Energy (MWh)				
Capacity (MW)				
Solar (excl. rooftop)				
Energy (MWh)				
Capacity (MW)				
Solar (rooftop)				
Energy (MWh)				
Capacity (MW)				
Hydro				
Energy (MWh)				
Capacity (MW)				
Geothermal				
Energy (MWh)				
Capacity (MW)				
Grid-Scale Storage				
Energy (MWh)				
Capacity (MW)				
Storage – V2G/B				
Energy (MWh)				
Capacity (MW)				
Hydro imports from Quebec				
Energy (MWh)				
Capacity (MW)				
Energy efficiency				
Energy (MWh)				

Capacity (MW)				
Demand response				
Energy (MWh)				
Capacity (MW)				

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Tables 1 and 2 show the potential energy and capacity from the following incremental non-emitting resources for each scenario. Guidehouse declines to provide values for demand response, vehicle-to-grid (V2G) storage, and energy efficiency. At the time of the analysis, the Low Carbon Pathways model did not include explicit modeling of demand response measures as a feature. Guidehouse implicitly accounted for the impact of demand response in the transportation sector when developing the demand forecasts. Guidehouse estimated that the managed charging of electric vehicles will be an impactful demand response measure that will shape the hourly electric load profile of the transportation sector. To implicitly account for the impact of demand response, the analysis used separate electric load shapes for the buildings and transportation sectors that do not have coincident peaks. V2G technologies were out of scope for this study, so Guidehouse cannot provide energy and capacity values for these resources. For energy efficiency, Guidehouse modeled the impacts of energy efficiency improvements, but did not explicitly model energy efficiency as an electricity resource.

Table 1
Diversified Scenario: Electricity Resource Potential – Energy and Capacity

	2020	2030	2040	2050	
Wind					
Energy (MWh)	22,610,240	84,285,760	175,416,914	307,794,888	/u
Capacity (MW)	5,534	20,684	42,934	75,334	/u
Solar (excl. rooftop)					/u
Energy (MWh)	661,294	953,204	8,484,051	12,000,808	/u
Capacity (MW)	478	689	6,132	8,674	/u
Hydro					
Energy (MWh)	38,380,000	38,482,799	38,482,799	38,482,799	/u
Capacity (MW)	9,255	9,272	9,272	9,272	
Grid-Scale Geothermal					
Energy (MWh)	0	0	0	0	
Capacity (MW)	0	0	0	0	
Grid-Scale Storage					
Energy (MWh) Net	-48,014	-442,909	-599,592	-974,573	/u

Energy (MWh) Dispatched	192,054	2,375,678	3,319,567	5,432,547	/u
Capacity (MW)	175	1,473	3,875	6,475	
Hydro imports from Quebec					
Energy (MWh)	2,007,948	1,169,234	2,583,684	2,188,280	/u
Electric Import Capacity from Quebec (MW)	2,350	3,850	5,350	6,850	/u

Table 2
Electrification Scenario: Electricity Resource Potential – Energy and Capacity

	2020	**2030**	**2040**	**2050**	
Wind					
Energy (MWh)	22,581,186	84,301,634	175,104,150	293,471,513	/u
Capacity (MW)	5,534	20,684	42,934	71,831	/u
Solar (excl. rooftop)					
Energy (MWh)	661,294	5,053,726	8,231,526	11,748,282	/u
Capacity (MW)	478	3,653	5,950	8,492	/u
Hydro					
Energy (MWh)	38,412,241	38,482,799	41,597,951	41,597,951	/u
Capacity (MW)	9,255	9,272	10,022	10,022	/u
Grid-Scale Geothermal					
Energy (MWh)	0	0	0	0	
Capacity (MW)	0	0	0	0	
Grid-Scale Storage					
Energy (MWh) Net	-48,014	-365,960	-815,740	-1,087,316	/u
Energy (MWh) Dispatched	192,054	1,967,744	4,536,098	6,073,779	/u
Capacity (MW)	175	1,473	4,097	6,697	/u
Hydro imports from Quebec					
Energy (MWh)	2,011,135	3,750,525	3,628,686	4,031,720	/u
Electric Import Capacity from Quebec (MW)	2,350	3,850	5,350	6,850	/u

ENBRIDGE GAS INC.

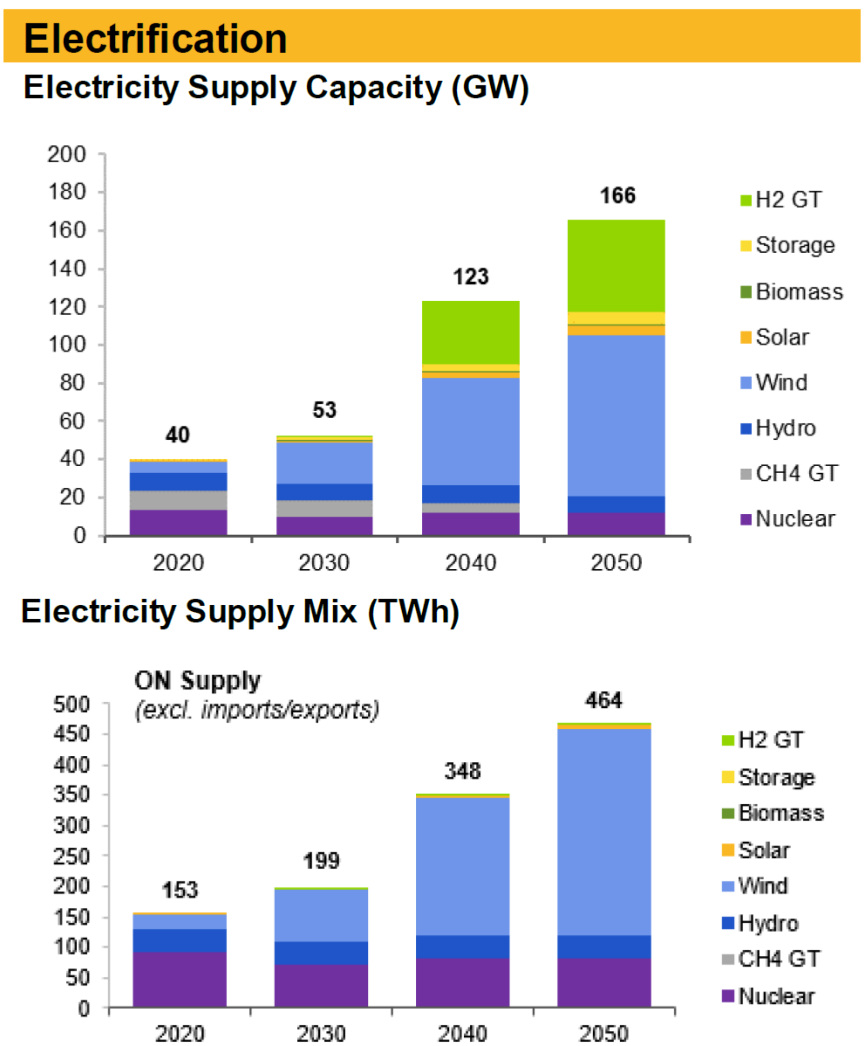
Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 36

Preamble:



Question(s):

a) How did Guidehouse determine the load factor for (i) all electricity consumption, (ii) EVs, and (iii) space heating, and (iv) water heating.

b) Please complete the following table showing the forecast load factor for all electricity consumption:

Electricity Load Factor				
	2020	2030	2040	2050
Diversified				
Energy demand (MWh)				
Capacity demand (MW)				
Load factor				
Electrified				
Energy demand (MWh)				
Capacity demand (MW)				
Load factor				

c) Please complete the following table showing the load factor for EVs.

Electric Vehicle Load Factor				
	2020	2030	2040	2050
Diversified				
Energy demand (MWh)				
Demand at system peak (MW)				
Load factor				
Electrified				
Energy demand (MWh)				
Demand at system peak (MW)				
Load factor				

d) Please complete the following table showing the electric load factor for space and water heating.

Electric Load Factor for Space and Water Heating				
	2020	2030	2040	2050
Diversified				

Energy demand (MWh)				
Demand at system peak (MW)				
Load factor				
Electrified				
Energy demand (MWh)				
Demand at system peak (MW)				
Load factor				

e) If possible, please reproduce (g) with a breakdown between space and water heating. If that is not possible, please provide a rough estimate of the contribution of each (%) to the overall space and water heating load.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Guidehouse did not calculate a load factor for overall electricity use or for individual end uses of electricity. The process for determining annual electricity use and peak load is as follows:

   i. For each sector included in the analysis (i.e., buildings, transportation, and industry), Guidehouse forecast the annual electricity consumption based on reference case IESO APO forecasts, with interventions to model increased energy efficiency, electrification, and technology switching (i.e., electric resistance space heating changing to electric heat pump).

   ii. Guidehouse developed electric load shape profiles for each sector for each decade and used these load shapes to distribute annual electricity consumption on an hourly basis for each sector. The load shape profiles for the buildings and transportation sectors are different for each decade of the analysis, reflecting the electrification that is assumed to occur in those sectors.

   iii. Guidehouse summed the demand for all sectors in each hour to determine total hourly electric demand.

   iv. Guidehouse identified the hour of peak coincident electricity demand in each decade and referenced each sector's contribution to coincident peak electric demand in those hours.

b) Table 1 describes total annual electricity use and peak electricity demand for all sectors. Guidehouse declines to provide economy-wide electricity load factors because Guidehouse did not calculate them in the demand model.

Table 1

Total Electricity Use					
	2020	2030	2040	2050	
Diversified					
Annual Electricity Demand (TWh)	135.1	184.2	230.3	280.4	/u
Capacity demand (MW)	21,525	32,421	42,565	51,057	/u
Electrification					
Annual Electricity Demand (TWh)	135.1	205.8	327.8	413.3	/u
Capacity demand (MW)	21,525	37,965	68,283	82,143	/u

c) Table 2 describes annual electricity use and peak electricity demand for the transportation sector. Guidehouse declines to provide load factors for the transportation sector or for EVs specifically, because Guidehouse did not calculate them in the demand model. Note that the transportation sector's contribution to peak demand is influenced by the hour in which coincident peak demand occurs. In the Diversified Scenario, the electric peak hour shifts to the late evening in 2050 due to transportation electrification. /u

Table 2

Transportation Sector Electricity Use					
	2020	2030	2040	2050	
Diversified					
Annual Electricity Demand (TWh)	0.0	24.6	51.4	80.1	
Demand at system peak (MW)	0	4,064	3,984	12,870	/u
Electrification					
Annual Electricity Demand (TWh)	0.0	37.2	78.3	122.7	
Demand at system peak (MW)	0	3,208	6,826	10,794	/u

d) Table 3 describes annual electricity use and coincident peak electricity demand for the buildings sector. Guidehouse declines to provide load factors for the buildings sector because Guidehouse did not calculate them in the demand model. Guidehouse notes that Figure 26 of the P2NZ report presents peak demand specific to the buildings sector load, which is a different value than the buildings sector contribution to coincident peak load depicted below. The response at Exhibit I.1.10-ED-74 describes the system peak hours in each decade for each scenario and illustrates that the peak hour changes over time in the Diversified scenario due to the /u /u changing saturation of electric vehicles and electrification of building heat.

Table 3

Buildings Sector Electricity Use					
	2020	2030	2040	2050	
Diversified					
Annual Electricity Demand (TWh)	98.6	118.0	134.2	141.3	/u
Demand at system peak (MW)	15,713	21,990	32,333	29,704	/u
Electrification					
Annual Electricity Demand (TWh)	98.6	125.8	172.4	187.2	/u
Demand at system peak (MW)	15,713	28,682	52,248	59,730	/u

e) Guidehouse assumes that the question refers to sub-part (d) instead of sub-part (g) as stated. Table 4 describes forecast electricity consumption for space heating and water heating end uses, by decade, for both scenarios. Guidehouse declines to provide peak electricity demand or load factors for these individual end uses because Guidehouse did not calculate them in the demand model.

Table 4

Buildings Sector Space Heating and Water Heating Electricity Use					
	2020	2030	2040	2050	
Diversified					
Space Heating Annual Electricity Demand (TWh)	16.6	31.3	38.8	35.1	/u
Water Heating Annual Electricity Demand (TWh)	4.4	4.5	4.9	9.2	/u
Electrification					
Space Heating Annual Electricity Demand (TWh)	16.6	35.2	55.0	55.9	/u
Water Heating Annual Electricity Demand (TWh)	4.4	4.5	15.1	20.3	/u

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 36

Preamble:

These questions relate to Guidehouse's calcualtion of annual and peak electricity demand arising from space conditioning and water cooling in different scenarios.

Question(s):

a) Please complete the following table regarding residential space and water heating equipment in each scenario. If we are missing different kinds of systems, please add those.

Residential Space and Water Heating Equipment				
	2020	2030	2040	2050
Number of customers				
Diversified				
Fully electrified				
Resistance				
Heat pump				
Hybrid				
Gaseous only				
Gas furnace				
Gas heat pump				
Other				
Electrified				
Fully electrified				
Resistance				
Heat pump				
Hybrid				
Gaseous only				
Gas furnace				
Gas heat pump				
Other				
Percent of customers				
Diversified				

Fully electrified				
Resistance				
Heat pump				
Hybrid				
Gaseous only				
Gas furnace				
Gas heat pump				
Other				
Electrified				
Fully electrified				
Resistance				
Heat pump				
Hybrid				
Gaseous only				
Gas furnace				
Gas heat pump				
Other				
Fully electrified				

b) Please provide the following assumptions as used in Guidehouse's estimate of the impact of residential space and water heating options on electricity demand (both energy (kWh) and peak demand (kW)). Where no assumption was explicitly made, please provide the implied value based on the analysis inputs and outputs. If the numbers change over time, please provide those (at least with the granularity of each decade).

i. Average home demand for space heating at the time of the electricity system peak hour (BTU or kW of heat);
ii. Average home hot water demand at the time of the electricity system peak (BTU or kW);
iii. Average or design day outdoor temperature at the time of the electricity system peak hour;
iv. For the average home with fully electric heat pump space and water heating:
    A. Size of ASHP (BTU);
    B. Size of resistance backup (kW);
    C. Seasonal COP of ASHP (region 5):
    D. COP of ASHP at time of electricity system winter peak hour;
    E. HWHP COP;
    F. Contribution to electricity system winter peak hour for space/water heating without accounting for diversity / coincidence (kW);
    G. Coincidence factor for heating;
    H. Contribution to electricity system winter peak hour for space/water heating after accounting for diversity / coincidence (kW);
    I. Breakdown of contribution to winter peak hour by space and water heating, with and without accounting for coincidence/diversity;

J. Annual electricity demand for heating (kWh);
K. SEER of the ASHP for cooling;
L. COP of ASHP cooling at time of electricity system summer peak hour;
M. Coincidence factor for cooling;
N. Contribution to electricity system summer peak hour with and without accounting for coincidence / diversity(kW);
O. Annual electricity demand for cooling (kWh);

v. For the average home with a hybrid system;
   A. Size of ASHP (BTU);
   B. Seasonal COP of ASHP (region 5):
   C. COP of ASHP at time of electricity system winter peak hour;
   D. HWHP COP;
   E. Contribution to electricity system winter peak hour for space/water heating without accounting for diversity / coincidence (kW);
   F. Coincidence factor for heating;
   G. Contribution to electricity system winter peak hour for space/water heating after accounting for diversity / coincidence (kW);
   H. Breakdown of contribution to winter peak hour by space and water heating, with and without accounting for coincidence/diversity;
   I. Annual electricity demand for heating (kWh);
   J. SEER of the ASHP for cooling;
   K. COP of ASHP cooling at time of electricity system summer peak hour;
   L. Coincidence factor for cooling;
   M. Contribution to electricity system summer peak hour with and without accounting for coincidence / diversity(kW);
   N. Annual electricity demand for cooling (kWh);

vi. For the average home with gaseous only heating:
   A. Size of GHP (BTU);
   B. Seasonal COP of GHP (region 5):
   C. COP of GHP at time of electricity system winter peak hour;
   D. Contribution to electricity system winter peak hour for space/water heating without accounting for diversity / coincidence (kW);
   E. Coincidence factor for heating;
   F. Contribution to electricity system winter peak hour for space/water heating after accounting for diversity / coincidence (kW);
   G. Annual electricity demand for heating (kWh);
   H. SEER of the air conditioner for cooling;
   I. Coincidence factor for cooling;
   J. Contribution to electricity system summer peak hour with and without accounting for coincidence / diversity(kW);
   K. Annual electricity demand for cooling (kWh);

c) Please provide all details, calculations, assumptions, and spreadsheets used by Guidehouse to calculate the annual and peak annual electricity demand from residential space and water heating.

d) To calculate the peak hour electricity demand from ASHPs, what temperature(s) did Guidehouse assume for planning/design purposes? Please provide all details and explain the choices made.

e) What temperature(s) at the time of the electricity system peak hour does the IESO use when planning for electricity capacity adequacy?

f) When Guidehouse calculated the impact of ASHPs on the peak and annual electricity demand, did it net out the existing electricity demand from the blower and control systems for a conventional gas heating system? Please explain the choices made.

g) When Guidehouse calculated the impact of ASHPs on the peak and annual electricity demand, did it account for the fact that ASHPs typically reduce a building's summer peak electricity draw through more efficient cooling than traditional air conditioning systems?

h) Please provide a table with a breakdown between air and ground source heat pumps in each scenario for each decade.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Please see response at Exhibit I.1.10-SEC-52 Attachment 1 for a detailed view of the number and proportion of heating system types projected for the Diversified and Electrification scenarios by decade.

b)

i.-ii. The P2NZ study used a top-down approach and did not model the electric consumption or coincident peak demand of individual buildings or individual heat pump systems. Please see response at Exhibit I.1.10-ED-52 parts a-d) for a detailed discussion of how the P2NZ modeled peak system loads.

iii. Please see response at Exhibit I.1.10-ED-52 part f) for a description of outdoor temperatures at the time of electricity system peak.

iv. For the average home with fully electric heat pump space and water heating:

A, C, K Please see Exhibit I.1.10-GEC-24 for a description of system size, COP, and SEER for all electric air-source heat pump systems.
B Guidehouse declines to answer this question because Guidehouse did not make an explicit assumption about the size of backup resistance heaters for air-source heat pumps.
D, F-J, L-O The P2NZ study used a top-down approach and did not model the electric consumption, coincidence factors, or coincident peak demand of individual buildings or individual heat pump systems. Please see response at Exhibit I.1.10-ED-52 parts a-d) for a detailed discussion of how the P2NZ modeled peak system loads.
E Please see response at Exhibit I.1.10-ED-50 part a) for a description of heat pump water heater efficiency assumptions.

v. For the average home with a hybrid system;

A-B, J Please see response at Exhibit I.1.10-GEC-24 for a description of system size, COP, and SEER for hybrid heat pump systems.
C, E-H, I-N The P2NZ study used a top-down approach and did not model the electric consumption, coincidence factors, or coincident peak demand of individual buildings or individual heat pump systems. Please see response at Exhibit I.1.10-ED-52 parts a-d) for a detailed discussion of how the P2NZ modeled peak system loads.
D Please see response at Exhibit I.1.10-ED-50 part a) for a description of heat pump water heater efficiency assumptions.

vii. For the average home with gaseous only heating:

A-B, H Please see response at Exhibit I.1.10-GEC-24 for a description of system size, COP, and SEER for gas heat pump systems.
C-G, I-K The P2NZ study used a top-down approach and did not model the electric consumption, coincidence factors, or coincident peak demand of individual buildings or individual heat pump systems. Please see response at Exhibit I.1.10-ED-52 parts a-d) for a detailed discussion of how the P2NZ modeled peak system loads.

c) The Low Carbon Pathways (LCP) model used in the P2NZ study is a proprietary model developed by Guidehouse and is not available for commercial use. Therefore, Guidehouse declines to provide the model for review. Please see response at Exhibit I.1.10-SEC-48 for details on the form and function of the LCP model.

d) Please see response at Exhibit I.1.10-ED-52 part f) for a description of outdoor temperatures at the time of electricity system peak.

e) Guidehouse declines to answer this question because Guidehouse did not review the IESO's design temperature specification.

f) The P2NZ study used a top-down approach and did not model the electric consumption, coincidence factors, or coincident peak demand of individual buildings or individual heat pump systems.

g) Guidehouse assumed that ASHPs provide more efficient cooling than currently installed air conditioning systems. However, Guidehouse also assumed that widescale electrification via ASHP adoption will lead to a greater proportion of homes using an air conditioning function during summer peak. Statistics Canada reports that in 2019, 82% of homes in Ontario had some type of air conditioning system. Guidehouse assumed that ASHP adoption would increase the saturation of air conditioning systems in Ontario to over 95% of buildings.

h) Please see response at Exhibit I.1.10-SEC-52, Attachment 1 for a detailed view of the number of air-source and ground-source heat pumps projected for the Diversified and Electrification scenarios by decade.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 36

Preamble:

These questions relate to Guidehouse's calcualtion of annual and peak electricity demand arising from space conditioning and water cooling in different scenarios.

Question(s):

a) Please provide a table comparing Guidehouse's inputs and outputs regarding the annual and peak electricity demand arising from a switch to ASHPs with the inputs in the New England ISO's 2022 Analysis found here: https://www.iso-ne.com/static-assets/documents/2022/04/final_2022_heat_elec_forecast.pdf. Note in particular page 26, which suggests a net contribution of approximately 5 kW, not accounting for diversity / coincidence factors.

b) With respect to the regions used for calculating heat pump performance (HSPF & seasonal COP, sCOP), does Guidehouse agree with NRCan that "region 5 would cover most of the southern half of the provinces in Canada" and that "region 5 HSPF is most reflective of heat pump performance in the Ottawa region."

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) The *Pathways to Net-Zero Emissions for Ontario* Study used a top-down approach and did not model the electric consumption or coincident peak demand of individual buildings or individual heat pump systems. Instead, our approach estimated the total province-wide electric consumption of ASHPs and GSHPs that would result from the electrification of residential and commercial heating loads and from the adoption of heat pumps in new construction. Guidehouse does not have individual building estimates to compare to the referenced report from the New England ISO.

b) Guidehouse does not take a position on which regional HSPF is most reflective of heat pump performance in the Ottawa region.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 36

Preamble:

These questions relate to Guidehouse's calcualtion of annual and peak electricity demand arising from space conditioning and water cooling in different scenarios and the assuming efficiencies and forecast future efficiencies of heating equipment.

Question(s):

a) Please complete the following table containing assumptions in Guidehouse's analysis (explicit or implied) regarding technology improvements relating to home heating and cooling. If these assumptions differ between the scenarios, please provide a copy of this table for each scenario.

Guidehouse Forecasts re Heating Technology Improvements				
	2020	2030	2040	2050
Air source heat pump				
Seasonal COP (#)				
COP at time electricity system coincident winter peak (#)				
Electricity demand at time of electricity system coincident winter peak (kW)[1]				
SEER at the time of electricity system coincident peak (kW)				
Equipment cost				
Electric heat pump water heater				
Seasonal COP (#)				
COP at time electricity system coincident winter peak (#)				

[1] Please account for diversity / coincidence and include the total load, including the resistance heating.

Electricity demand at time of electricity system coincident winter peak (kW)[2]				
SEER at the time of electricity system coincident peak (kW)				
Equipment Cost				
Gas heat pump				
Seasonal COP (#)				
COP at time electricity system coincident winter peak (#)				
Electricity demand at time of electricity system coincident winter peak (kW)[3]				
SEER at the time of electricity system coincident peak (kW)				
Equipment Cost				
CCS for blue hydrogen				
Capture rate (%)				
CCS cost ($/PJ)				
Electrolyser for green hydrogen				
Cost ($/PJ)				

b) With respect to the regions used for calculating heat pump performance (HSPF & seasonal COP, sCOP), does Guidehouse agree with NRCan that “region 5 would cover most of the southern half of the provinces in Canada” and that “region 5 HSPF is most reflective of heat pump performance in the Ottawa region.”

c) What are the three most efficient centrally-ducted cold climate air source heat pumps currently available in the North American market with 3-ton capacity? Please complete the following table. (We are seeking this, in part, to compare the best current units with Guidehouse’s forecast of future standard efficiency levels.) If Guidehouse uses a source other than NEEP, please explain why.

Most Efficient Cold Climate Air Source Heat Pumps (Three Ton, Centrally Ducted, North American Market Available)					
	HSPF (IV)	HSPF (V)	sCOP (V)	COP (-25 °C)[4]	Capacity (BTU, -25 °C)[5]
Unit 1					

[2] Please account for diversity / coincidence and include the total load, including the resistance heating.
[3] This would include the circulation fans, outdoor unit, controls, etc. Please account for diversity / coincidence and include the total load, including the resistance heating.
[4] If this precise figure is not available, please provide the COP at the lowest rated temperature.
[5]

Unit 2					
Unit 3					

d) What are the three most efficient centrally-ducted gas heat pumps currently available in the North American market with 3-ton capacity? Please complete the following table. (We are seeking this, in part, to compare the best current units with Guidehouse's forecast of future standard efficiency levels.

Most Efficient Gas Heat Pumps (Three Ton, Centrally Ducted, North American Market Available)					
	HSPF (IV)	HSPF (V)	sCOP (V)	COP (-25 °C)[6]	Capacity (BTU, -25 °C)[7]
Unit 1					
Unit 2					
Unit 3					

e) Please provide a table detailing the improvements in overall efficiency (sCOP), cold climate efficiency, and cold climate capacity of heat pumps since 2000.

f) ISO New England believes that "ASHP technologies deployed in the coming years are expected to improve in terms of their overall coefficient of performance (COP)." Does Guidehouse agree?

g) (j) What is the maximum theoretical COP for an ASHP?

<u>Response:</u>

a) Guidehouse declines to provide COP, electric demand, and SEER at the coincident seasonal peak because these values were not estimated as part of the P2NZ analysis. Guidehouse understands that SEER is a seasonal efficiency metric and cannot be used to quantify system performance at a single point in time. Guidehouse declines to provide equipment costs for heat pump water heaters because the P2NZ Study did not account for the cost of water heater conversions. Guidehouse declines to provide CCS costs and electrolyzer costs on a $/PJ basis because the cost accounting for the P2NZ Study accounted for total costs of green and blue hydrogen production and did not levelized costs on a per-energy basis. The table below provides the seasonal COP and equipment cost by decade.

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[6] If this precise figure is not available, please provide the COP at the lowest rated temperature.
[7]

Guidehouse Forecasts re Heating Technology Improvements				
	2020	**2030**	**2040**	**2050**
Air source heat pump				
Seasonal COP (#)	2.8	2.9	3.1	3.2
Equipment cost (real 2020$ CAD)	$11,100	$10,545	$9,990	$9,435
Electric heat pump water heater				
Seasonal COP (#)	3	3.2	3.3	3.5
Gas heat pump				
Seasonal COP (#)	1.2	1.3	1.3	1.4
Equipment Cost (real 2020$ CAD)	$12,200	$11,590	$10,980	$10,370
CCS for blue hydrogen				
Capture rate (%)	95%	95%	95%	95%

b) Guidehouse does not take a position on which regional HSPF is most reflective of heat pump performance in the Ottawa region.

c) Guidehouse declines to answer this question because a market scan of cold climate air source heat pumps was outside the scope of the P2NZ analysis.

d) Guidehouse declines to answer this question because a market scan of gas heat pumps was outside the scope of the P2NZ analysis.

e) Guidehouse declines to answer this question because a study of historical heat pump improvements was outside the scope of the P2NZ Study.

f) For the P2NZ Study, Guidehouse assumed that the average seasonal efficiency of new air-source heat pumps, new gas heat pumps, and new electric heat pump water heaters would improve by 15% from 2020 to 2050. These efficiency improvements are reflected in the table provided for (a) above. Guidehouse assumed that these efficiency improvements would progress on a linear path over the 2020 to 2050 time period.

g) Guidehouse declines to answer this question because Guidehouse did not calculate the maximum theoretical COP for an ASHP as part of the P2NZ Study.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 36

Question(s):

Please provide the following figures:

a) Did Guidehouse analyze the capacity of electric thermal storage units to cost-effectively reduce the coincident peak demand of fully-electrified heating systems? If not, why not? If yes, please provide that analysis.

b) Please confirm that there are electric thermal storage units available in Ontario (e.g. those from SSi Energy, Stash, and Steffes).

c) If all heating in homes were to be fully electrified through heat pumps, what would the aggregate co-incident winter peak demand from the heat pumps be (i) without electric thermal storage and (ii) with electric thermal storage?

d) Why did Guidehouse model a 55% penetration rate for gas heat pumps by 2050 but zero penetration for electric thermal storage, even though gas heat pumps are not currently available in the Ontario market (according to Enbridge in its recent DSM proceeding) whereas electric thermal storage units are?

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Guidehouse did not model the adoption of electric thermal storage units. Guidehouse's model of future building sector energy demand focused on interventions that reduce total energy demand (e.g., building retrofits, heat pump conversions, and energy efficiency measures). Guidehouse understands that thermal storage units may shift the time of energy consumption but do not reduce annual energy usage.

b) Guidehouse confirms that SSI Energy, Stash, and Steffes advertise thermal storage products for sale. Guidehouse did not conduct market research to assess the availability of these products in Ontario.

c) Guidehouse modeled the coincident peak load by sector (e.g., buildings, transportation, and industry), but Guidehouse did not model the contributions of individual end uses (e.g., space heating) to the coincident electric peak load. The electric peak load from the buildings sectors is provided for the Diversified scenario, the Electrification scenario, and the Hybrid Heating sensitivity case (sensitivity #4) in Figure 26 of the P2NZ Report. Additionally, as noted above, Guidehouse did not model adoption of electric thermal storage systems.

d) As noted in response to part a), Guidehouse's model of future building sector energy demand focused on interventions that reduce total energy demand. Gas-powered heat pump units are rated at over 100% efficiency and, compared to baseline natural gas furnaces and boilers, gas-powered heat pump units improve heating efficiency and reduce total energy demand. Guidehouse understands that thermal storage units may shift the time of energy consumption but do not reduce annual energy usage.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 36

Question(s):

Please provide the following figures:

a) Annual energy consumption (kWh) from the IESO-controlled grid of an air-source heat pump;

b) An air-source heat pump's kW demand from the IESO-controlled at the time of the IESO-controlled grid's peak winter demand hour;

c) Annual energy consumption (kWh) from the IESO-controlled grid of a ground-source heat pump;

d) A ground-source heat pump's kW demand from the IESO-controlled at the time of the IESO-controlled grid's peak winter demand hour;

e) Time of day of IESO-controlled grid's peak winter demand hour;

f) Outside temperature at time of the IESO-controlled grid's peak winter demand hour;

g) Coincidence demand factor of air-source heat pumps at time of IESO-controlled grid's peak winter demand hour; and

h) Coincidence demand factor of ground-source heat pumps at time of IESO-controlled grid's peak winter demand hour.

Response:

The following response was provided by Guidehouse Canada Ltd.

a-d) The *Pathways to Net-Zero Emissions for Ontario* Study used a top-down approach and did not model the electric consumption or coincident peak demand of individual buildings or individual heat pump systems. Instead, our approach estimated the total province-wide electric consumption of ASHPs and GSHPs that would result from the electrification of residential and commercial heating loads and from the adoption of heat pumps in new construction.

The total province-wide electric consumption from ASHPs is the sum of (1) Consumption from existing ASHP systems, (2) consumption from ASHPs added in new construction, and (3) incremental new ASHP consumption from systems converted from non-HP heating. We also accounted for consumption reductions that result from building shell improvements.

For each decade, we projected and modeled the amount of heating load that would switch from being served by gas, other fuels, or electric resistance heat to being served by ASHPs or GSHPs. For each non-HP system type that was electrified to an ASHP, we used a ratio of system efficiencies to calculate the incremental new ASHP energy consumption that would result from electrification. The following equation represents our ASHP consumption calculations:

$$(\text{\% of load electrified}_{non-HP\ type}) \times (\text{Consumption}_{non-HP\ type}) \times \left(\frac{\text{System efficiency}_{non-HP\ type}}{\text{System efficiency}_{HP\ type}}\right) = \text{Incremental New Consumption}_{HP\ type}$$

where:
non-HP types = natural gas combustion, propane combustion, fuel oil combustion, wood combustion, and electric resistance heating
HP types = air-source heat pump, ground-source heat pump

This method accounts for the inherent efficiency differences between non-HP and HP systems. This calculation was performed at the province-wide level and was not based on a bottom-up analysis of per-building consumption. To estimate hourly electric demand from buildings, our method used a sector-specific 8760-hour load shape to distribute the annual electric consumption for the buildings sector to each hour of the year. This top-down method determines the buildings sector’s contribution to Ontario’s peak electric load, but it does not compute the kW of demand at the scale of an individual heat pump or an individual building.

e) The winter peak hour in the year 2050 is at a different time in the two scenarios /u
modeled in the *Pathways to Net-Zero Emissions for Ontario* Study. In the Diversified
scenario the winter peak in 2050 is in the hour 6:00-7:00pm. The peak hour is late in /u
the day because it is driven by the electric vehicle (EV) charging load shape since, in
this scenario, the limited electrification of building heating means reduces the
influence that building heating demand has on the coincident system peak. In the
Electrification scenario, the winter peak in 2050 is in the hour 7:00-8:00am. This is /u

driven primarily by the electrification of building heat, with some contribution from EV charging.

f) Diversified scenario: The average Winter temperature in the hour 6:00-7:00pm is -2 degrees Celsius. /u

Electrification scenario: The average Winter temperature in the hour 7:00-8:00am is -4.2 degrees Celsius.

This is based on Toronto historical weather. Source: Environment Canada, Average hourly temperature (degrees Celsius) over the 5-year period from 2017-2021 (inclusive)

g-h) As noted above, this study used a top-down approach. Our method did not directly calculate or employ coincidence demand factors for air-source or ground-source heat pumps, and we did not calculate the consumption or the contribution to peak demand from individual heat pumps at the building scale. Rather, our demand forecasts began with a reference case forecast of annual electric consumption (by sector and end use) and a scenario case forecast of annual natural gas consumption (by sector and end use) from Enbridge Gas's ETSA Study. Guidehouse estimated the scenario case total annual electric consumption in Ontario based on assumptions about interventions that improve energy efficiency, that displace methane with low-carbon gases, and that electrify gas-powered end uses. The response to questions (a)-(d) above describes how our high-level method estimates the annual consumption of electricity from ASHPs. As noted above, we estimated hourly electric demand by distributing the annual electric consumption forecast for each sector using a sector-specific 8760-hour load shape.

ENBRIDGE GAS INC.

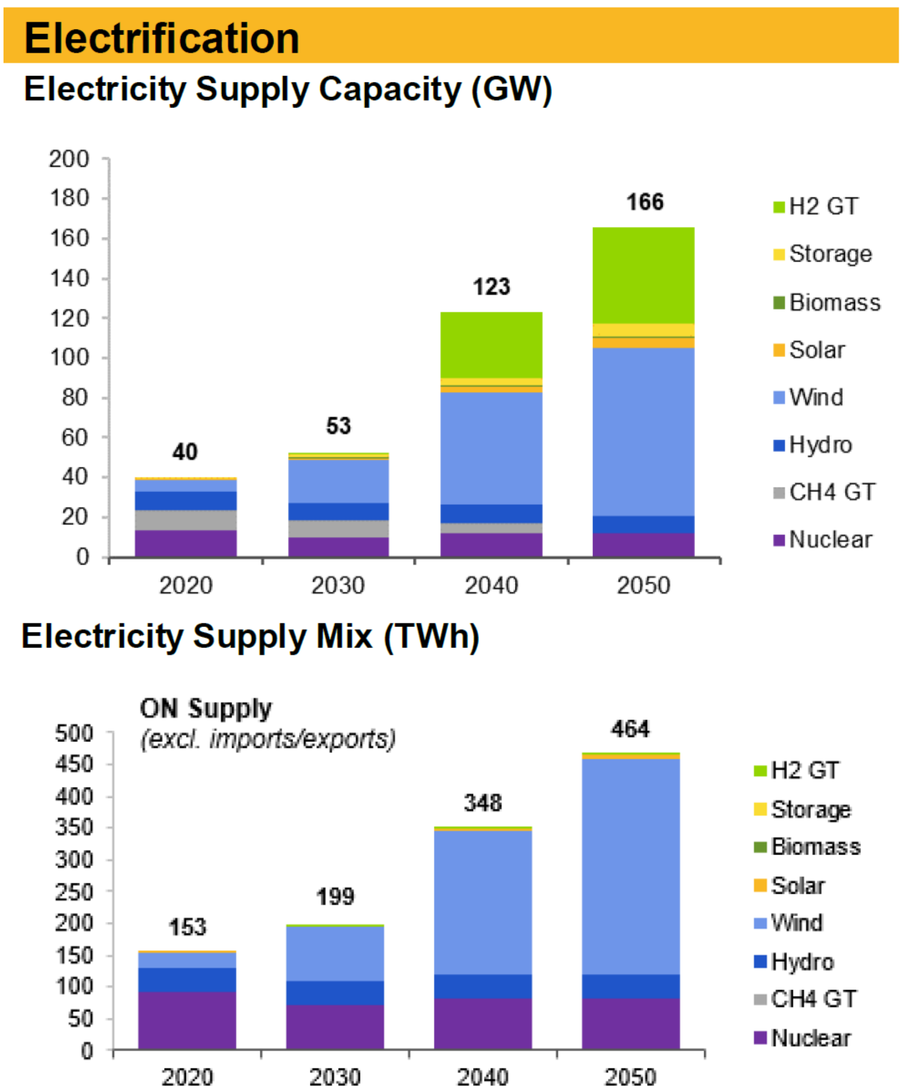
Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 36

Preamble:



Question(s):

a) Please provide a table comparing Guidehouse's estimates of the cost of storage capacity with the cost of capacity from vehicle-to-grid/building technology based on the IESO's DER Potential Study:

b) Please provide the cost-effective potential from vehicle-to-grid/building technology in 2020, 2030, 2040, and 2050 based on extrapolation from the IESO's DER Potential Study.

c) Approximately many vehicles are there in Ontario? {ADD FOOTNOTE] What is the technical potential for vehicle-to-grid/building technology by 2040 based on the number of vehicles in Ontario, an appropriate average battery size (e.g. 75 kWhs), and an estimate of the percent of vehicles that are electrified by 2040 (e.g. 90%)?

d) Please provide a table comparing Guidehouse's estimate of the average and marginal cost of zero-emitting resources with the average and marginal cost of the zero-emitting resources outlined in the IESO's DER Potential Study:

e) Please provide the cost-effective potential from DERs in 2020, 2030, 2040, and 2050 based on extrapolation from the IESO's DER Potential Study.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Guidehouse's estimate of the cost of battery storage technology is included in Table A-11 of the P2NZ Study and includes capital costs of installation (CONE) and fixed O&M costs (FOM) in 2030, 2040, and 2050. Guidehouse declines to compare the battery storage cost assumptions from the P2NZ Study to the IESO's estimates for V2B/G technology provided in the IESO Distributed Energy Resources (DER) Potential Study,[1] because Guidehouse has not independently verified the findings of the IESO DER Potential Study.

b) Guidehouse declines to answer this question because the IESO DER Potential Study provides estimates of measure-level potential in the year 2032 (Figure 5-7 in the IESO report), but the report provides no basis for interpolation or extrapolation of these estimates.

[1] IESO (2022). "Distributed Energy Resources (DER) Potential Study." Available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/derps/derps-20220930-final-report-volume-1.ashx

c) Guidehouse declines to answer this question because the Guidehouse transportation demand model for Ontario is specified in terms of passenger-kilometers and not in terms of vehicle counts. Guidehouse has not assessed the potential for vehicle-to-grid/building technology. Guidehouse estimates that, of the passenger-kilometers travelled in cars, approximately 67% of passenger-kilometers will be served by electrified transportation by 2040.

d) Guidehouse declines to answer this question because the analysis conducted for the P2NZ Study did not calculate the average or marginal costs of individual electric generating resources. Instead, the Low Carbon Pathways model estimates the total economy-wide cost of new generation resources by accounting for the capital cost of installing each resource (the cost of new resource, or CONE) and the fixed and variable operations & maintenance costs (FOM and VOM) associated with using each generation resource. Table A-11 of the *Pathways to Net Zero Emissions for Ontario* Study contains the CONE, FOM, and VOM assumptions for all of the modeled resources. However, these values are not comparable to the IESO's method of cost reporting.

e) Guidehouse declines to answer this question because the IESO DER Potential Study provides estimates of total DER potential in the years 2023, 2027, and 2032 (Table 5-6 of the IESO report), but the report provides no basis for interpolation or extrapolation of these estimates.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 36

Question(s):

a) Please complete the following table comparing the Guidehouse forecasts for the price of hydrogen power generation versus storage:

Guidehouse Cost Forecasts Regarding Peak Power Resources – Storage vs. Hydrogen				
	2020	2030	2040	2050
Hydrogen power generation – blue hydrogen				
Capacity ($/MW, levelized)				
Energy ($/MWh)				
Hydrogen power generation – green hydrogen				
Capacity ($/MW, levelized)				
Energy ($/MWh)				
Efficiency (%)[1]				
Grid-scale battery storage				
Capacity ($/MW, levelized)				
Energy ($/MWh)				
Efficiency (%)[2]				

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Guidehouse declines to answer the questions regarding unit costs of green hydrogen and blue hydrogen production. The purpose of the P2NZ report was to

[1] Efficiency is [power input into the electrolyser]/[power generated from the resulting hydrogen], accounting for all losses involved in the electrolysis, storage, transportation, and power generation steps.
[2] Efficiency is [power input into the battery]/[power drawn from the battery], accounting for all losses involved therein.

estimate the total costs for each scenario to achieve net-zero emissions by 2050. To estimate total costs, Guidehouse accounted for the capital cost of new hydrogen production projects (CONE), the fixed O&M costs (FOM) of operating hydrogen production capacity regardless of output, and the variable O&M costs (VOM) which scale based on production volume. Table A-11 of the P2NZ study provides these costs for the renewable electric generation capacity and electrolyzers used to produce green hydrogen, and for the steam methane reformation used to produce blue hydrogen.

Guidehouse did not estimate a cost per unit production of green hydrogen or blue hydrogen, as the intent of the study was not to model commodity costs or market prices for hydrogen.

For battery storage technologies, Guidehouse took a similar approach and estimated the capital cost of new battery installations and the costs of operating battery capacity. Table A-11 of the P2NZ study provides the CONE and FOM costs for battery capacity.

Guidehouse cannot determine the levelized cost of capacity or the cost per unit production of hydrogen and batteries from the output of our Low Carbon Pathways model because these costs would include other project parameters (e.g., taxes, cost of financing, etc.) that we have not estimated.

Table 1 provides Guidehouse's assumptions regarding the efficiency of hydrogen and battery technologies. Guidehouse declines to provide the full lifecycle efficiency of hydrogen generation, storage, and consumption. The P2NZ analysis accounted for efficiency losses at each of these steps but did not include a holistic lifecycle analysis of hydrogen efficiency.

Table 1
P2NZ Assumptions Regarding Efficiencies of Hydrogen and Battery Technologies

	2020	2030	2040	2050
Green hydrogen production				
Electrolyzer Efficiency (%)[3]	71%	71%	76%	80%
Hydrogen Salt Cavern Storage (%)[4]	99%	99%	99%	99%
Hydrogen-Fired Gas Turbines (%)[5]	42%	42%	42%	42%
Grid-scale battery storage				
Battery Efficiency (%)[6]	85%	85%	85%	85%

[3] Electrolyzer Efficiency is [energy content of hydrogen produced]/[power input into the electrolyser], accounting for losses involved in electrolysis.
[4] Salt Cavern Storage Efficiency is [hydrogen withdrawn from storage]/[hydrogen placed in storage]
[5] Gas Turbine Efficiency is [electric power output of turbine]/[energy content of hydrogen consumed]
[6] Battery Efficiency is [power drawn from the battery]/[power input into the battery].

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

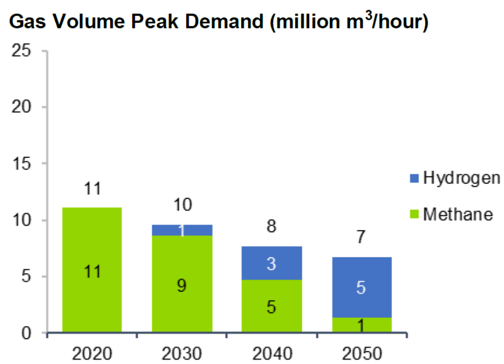
Issue:

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 38

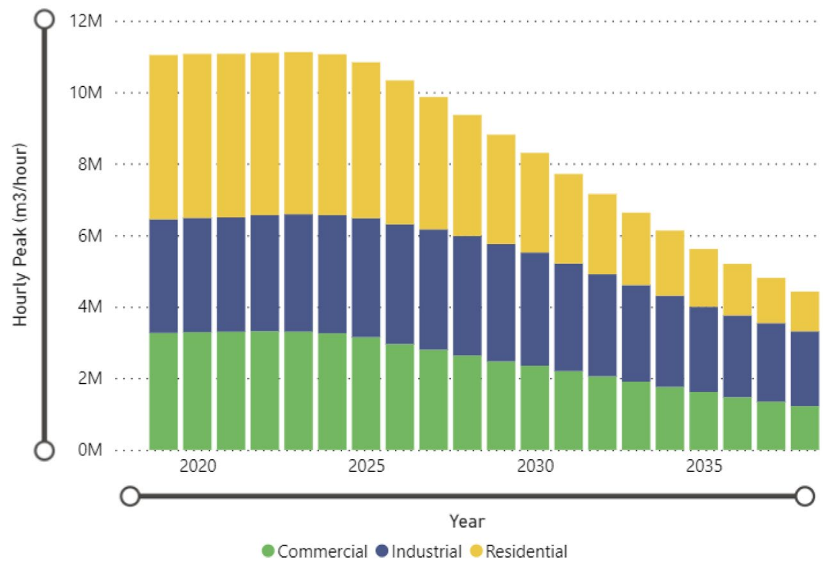
Preamble:

Electrification scenario peak demand per page 38 of the Guidehouse report:



Electrification scenario peak demand per the Posterity Group report at Exhibit 1, Tab 10, Schedule 5, Attachment 1, Page 72:

Exhibit 62 - Electricity Centric Scenario: Peak Hour by sector



Question(s):

a) Please provide a table reconciling the above figures. If necessary, please communicate with the Posterity Group to obtain the underlying data. Please explain any differences.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) The referenced charts describe different scopes of analysis. The chart from Posterity Group's Report projects the peak hour gas volumes that would be delivered by Enbridge Gas, and the projection from Posterity Group does not include gas demand from other sectors of the economy (e.g., transportation and industry) that may or may not be served by Enbridge Gas's gas network. Guidehouse's *Pathways to Net Zero Emissions for Ontario* Study describes gas volume peak demand for the whole province of Ontario, which includes gas end uses that may or may not be served by Enbridge Gas. As illustrated in Figure 8 of the P2NZ Report, the gas demand from the transportation and industry sectors are a substantial portion of gas demand, and the proportional consumption of these sectors is projected to increase over time. The Guidehouse figure also includes indirect gas demand that would be consumed for the production of blue hydrogen and for electric power generation. These indirect gas demand streams are described in Figure 15 of the P2NZ Report, under the subheading "Supply Mix for Direct & Indirect Gas Demand." Since the scope of the

Guidehouse chart is larger than and includes the scope of Posterity Group’s chart, it is logical that the peak volumes in the Guidehouse chart are larger than those in Posterity Group’s chart.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. B-1

Preamble:

“This study expands on previous energy transition scenario analysis (ETSA) done by Enbridge Gas that forecasts gas demand from 2020 to 2038. More specifically, this study expands the Enbridge Gas forecasts from 2038 to 2050 and develops electricity demand scenarios that are internally aligned with the underlying assumptions of Enbridge Gas’s gas forecasts. This section describes the forecasting methodology and presents the gas and electricity demand forecasts for the Diversified and Electrification scenarios. The Diversified and Electrification scenarios are intended to represent plausible, potential future visions of the Ontario energy system by 2050. They are not intended to represent the most optimal or perfect scenarios.”

Question(s):

a) It is unclear from the Guidehouse report which aspects of the scenarios were determined by Enbridge as part of its energy transition scenario analysis and which aspects were determined by Guidehouse through its own optimization. Please provide a table for each scenario listing all of the assumptions (including the values for assumptions) that were exogenous to Guidehouse’s work.

b) Why did Guidehouse not explore a scenario that did not rely on gaseous fuels delivered by pipelines, such as electrification where possible supplemented by hydrogen created onsite?

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Appendix A of the *Pathways to Net Zero Emissions for Ontario* provides tables of assumption values and clearly cites the values that were provided by Enbridge. The table below summarizes the sources of key modeling parameters employed in the study.

Modeling Parameter	Source
Natural gas price forecast	Determined by Guidehouse, based on Dawn Hub consensus forecast
Carbon price forecast	Sourced from ETSA
Discount rate	OEB guidance
Overall scenario definitions and high-level implications for the buildings, industry, transportation, and power sectors	Determined by Guidehouse, with input from Enbridge Gas subject matter experts
Estimated gas savings in the buildings sector due to retrofit building codes	Sourced from ETSA
Forecasts of natural gas, RNG, and hydrogen demand for Enbridge's gas system, for 2020-2038	Sourced from ETSA
Forecasts of economy-wide natural gas, RNG, and hydrogen demand for Ontario, for 2020-2050	Determined by Guidehouse
Forecasts of annual electricity consumption and peak electricity demand	Determined by Guidehouse
Forecasts of conversions of space conditioning and water heating technologies in the buildings sector	Determined by Guidehouse
Forecasts of conversions of transportation sector technologies	Determined by Guidehouse
Forecasts of conversions of industrial sector technologies	Determined by Guidehouse
Equipment efficiency ratings	Determined by Guidehouse
Electric generation capacity expansion	Determined by Guidehouse

b) The scope of work requested by Enbridge Gas included a detailed exploration and expansion of two ETSA scenarios through the 2050 timeframe with a target of net-zero emissions in 2050. Guidehouse did not consider additional scenarios outside the scope of work requested by Enbridge Gas.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

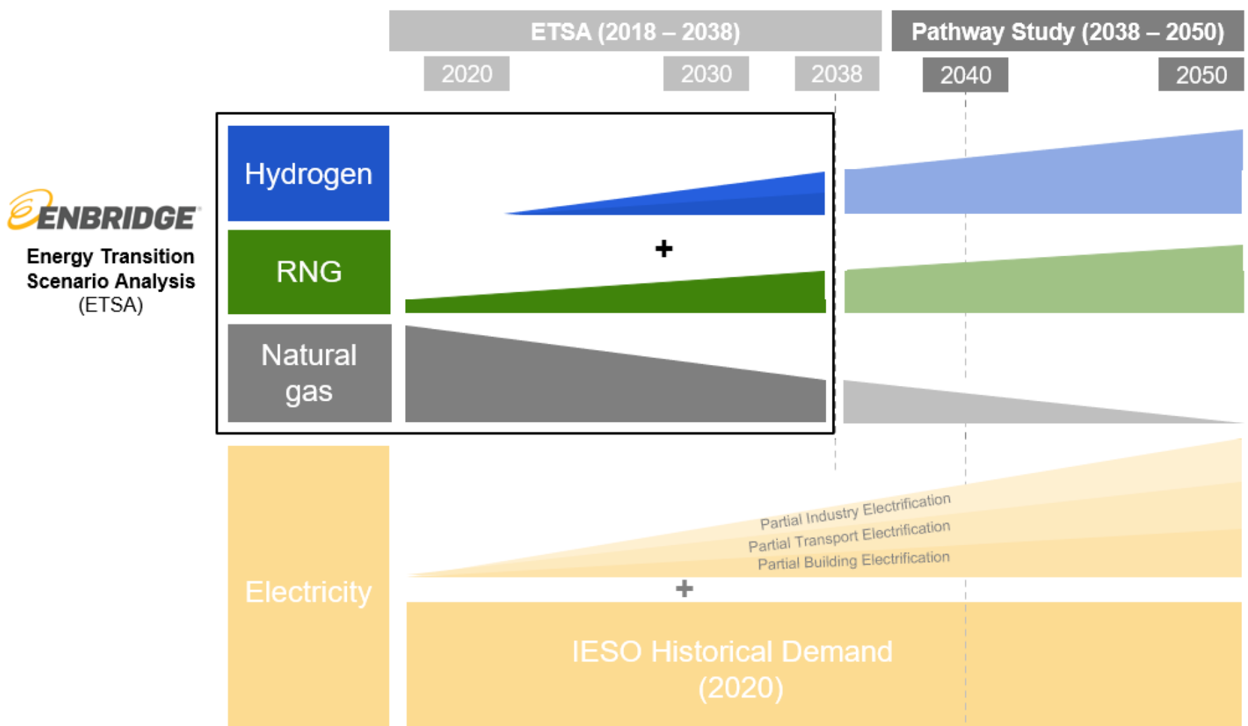
Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. B-1

Preamble:

Figure B-1. Graphical Representation of the Extrapolation Used to Develop the Demand Scenarios



Question(s):

a) Figure B-1 is a "Graphical Representation of the Extrapolation Used to Develop the Demand Scenarios." Please explain how this graphic can represent both scenarios.

b) When Guidehouse extrapolated the scenarios from the Enbridge ETSA, did it do so by maintaining the rate of increase or decrease in each fuel type constant as suggested by this graphic.? If not, please explain.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) In the *Pathways to Net Zero Emissions for Ontario* Study, Figure B-1 is conceptual in nature and is intended to illustrate that beyond the ETSA study period, the consumption of natural gas will continue to decline while the consumption of electricity, RNG, and hydrogen will continue to increase. This trend is true in both the Diversified and Electrification scenarios, albeit with different magnitudes of increase and decrease.

b) When Guidehouse extrapolated the scenarios from the Enbridge Gas ETSA, the extrapolations beyond the ETSA study period were guided by the requirement to achieve net-zero emissions by 2050. The extrapolations were not linear in shape as suggested by the conceptual illustration in Figure B-1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 35

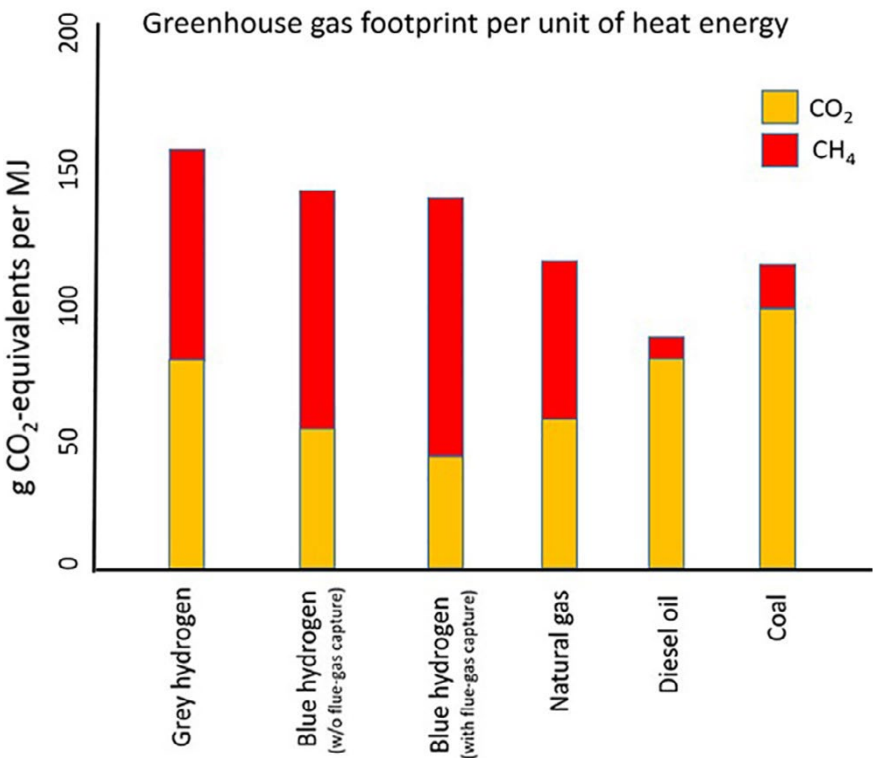
Preamble:

“Both scenarios require a large scale-up in wind capacity and hydrogen-fired gas turbines”

Question(s):

a) As detailed in the below figure from a peer-reviewed study published in an academic journal, electricity generated from blue hydrogen actually results in more carbon emissions than standard methane gas-fired generation.[1] Please produce a table comparing Guidehouse’s assumptions to the assumptions in that peer-reviewed study. In doing do, please separately address each of the figures Table 1 from the study, listing the figure from the study and Guidehouse’s different assumptions.

[1] Robert W. Howarth and Mark Z. Jackson, “How green is blue hydrogen?” *Energy Science & Engineering*, 26 July 2021; https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956



b) Wherever Guidehouse's assumptions in response to (a) are materially different, please describe the basis of Guidehouse's assumption versus the basis in the paper.

c) Please comment on the following conclusion from the report: "As we have demonstrated, far from being low emissions, blue hydrogen has emissions as large as or larger than those of natural gas used for heat (Figure 1; Table 1; Table 2). The small reduction in carbon dioxide emissions for blue hydrogen compared wit natural ga are more than made up for by the larger emissions of fugitive methane."

Response:

The following response was provided by Guidehouse Canada Ltd.:

a-c)

- Guidehouse reviewed the referenced study and determined that the study's findings regarding emissions from blue hydrogen production are overstated. The overall emissions rate of blue hydrogen production is fairly impactful to the results of the Pathways to Net-Zero Emissions for Ontario (P2NZ) Study, since a high emissions rate would make blue hydrogen less economical as an early source of hydrogen capacity. Guidehouse highlights the following points as they are the most impactful drivers of the referenced study's overstated emissions:

- **The referenced study uses 20-year global warming potential (GWP) values, instead of the standardly used 100-year GWP.** The current Intergovernmental Panel on Climate Change (IPCC) standard is to use 100-year GWP values, and the emissions factors in the P2NZ study are cited to sources that use a 100-year GWP as a basis for estimating the CO_2-equivalent emissions of fugitive upstream emissions. For reference, the 100-year GWP value for methane is 28, while the 20-year GWP value is 86[2] so the referenced study's use of a 20-year GWP will yield estimates of CO-equivalent emissions from fugitive methane that are nearly three times higher than impacts estimated with 100-year GWP values.

- **The referenced study assumes significant upstream methane leakage, mostly from gas extraction.** The referenced study assumes 3.5% methane leakage from extraction to end-use. In contrast, Enbridge Inc. has stated a goal of voluntarily reducing methane emissions across the value chain to 1% or less by 2025.[3] The P2NZ analysis uses a methane leakage rate of 0.4% as an average value over the 2020-2050 study period.

- **The referenced study assumes a CO2 capture rate of 85% from CCS.** The P2NZ Study assumes a CCS capture of 95%.

- In total, for blue hydrogen production, the referenced study assumes an emissions factor of 135 gCO_2e/MJ and the P2NZ Study assumes an emissions rate of 5.6 gCO_2e/MJ. For another point of comparison, a 2018 study from CE Delft[4] estimated that the CO_2 footprint of blue hydrogen is about 6.8 to 9.3 gCO_2e/MJ.

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[2] For more explanation see for instance https://www.gti.energy/wp-content/uploads/2019/02/CMR-Implications-Using-Different-GWP-Time-Horizons-White-Paper-2019.pdf

[3] Enbridge (2020). "Enbridge joins coalition of America's largest and most sustainable-minded natural gas players " Available at: https://www.enbridge.com/stories/2020/august/enbridge-joins-one-future-coalition-natural-gas-methane-reduction

[4] CE Delft (2018). "Feasibility study into blue hydrogen." CO2 footprint expressed in different units, as 0.82-1.12 kg CO2-eq./kg H2. Available at: https://cedelft.eu/wp-content/uploads/sites/2/2021/04/CE_Delft_9901_Feasibility_study_into_blue_hydrogen_DEF_bak.pdf

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Issue:

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 43

Preamble:

"Finally, end-user costs are $56 billion higher compared to the Diversified scenario. End-user costs are higher because of the high penetration of electric heat pumps which require significant upfront investment in equipment for geothermal heat pumps and costly building retrofits to maintain the same level of comfort for air-source heat pumps.88"

Question(s):

a) Are the above-noted building retrofits cost-effective?

b) Please provide the aggregate energy costs savings arising from the above-noted retrofits from 2020 to 2050. Where are these energy cost savings accounted for in the Guidehouse analysis, if anywhere?

c) Please provide the aggregate energy costs savings arising from the above-noted retrofits over the lifetime of those measures that accrue beyond 2050.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Assessing the cost effectiveness of building retrofits requires a projection of future utility rates for electricity ($/kWh) and gas service ($/GJ). In the *Pathways to Net Zero Emissions for Ontario* Study, Guidehouse assessed costs on an economy-wide basis and did not project the utility rates that customers will pay for energy. Thus, Guidehouse is unable to assess the cost-effectiveness of the building retrofits assumed in the analysis. Guidehouse notes that, in addition to utility rates, the cost-effectiveness of building retrofits will depend on federal incentives and other cost socialization measures that may be introduced in the future but are outside the scope of the study's cost analysis.

b) As noted above, the Guidehouse analysis assessed costs on an economy-wide basis. Cost reductions associated with building retrofits were estimated as follows. Guidehouse used an energy demand model for the buildings sector to estimate how building retrofits would reduce annual energy use for the buildings sector as a whole. Using these projections of annual energy use along with sector-specific electric load shapes, Guidehouse projected the coincident peak electric load in Ontario for each sector included in the analysis (buildings, transportation, and industry). These projections of coincident electric peak informed our capacity expansion modeling, which determined the amount of new electric generation capacity that will be needed to meet electric loads in the future. These forecasts of capacity expansion informed the Guidehouse cost analysis, which accounted for capital and operating expenses of the future energy system.

   Put simply, building retrofits lead to lower annual electric consumption in the buildings sector, which leads to lower coincident peak electric demand, which reduces the amount of new electric generating capacity needed, which reduces the costs estimated for building and operating new electric generation facilities. The cost reductions resulting from reduced energy use due to building retrofits are reflected in the "Electric System Costs" reported in Figure 18 of the *Pathways to Net Zero Emissions for Ontario* report provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2.

c) Guidehouse declines to answer this question because Guidehouse assessed costs on an economy-wide basis and did not project the utility rates that customers will pay for energy.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Issue:

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 43

Preamble:

"In the middle decade from 2030 to 2040, however, emissions costs are $49 billion higher in the Electrification scenario than in the Diversified scenario. This is because in that decade, carbon emissions will still be significant, and the price of carbon will have risen significantly. The Electrification scenario uses a higher projected price of carbon compared to the Diversified scenario, resulting in higher emissions costs in that decade."

Question(s):

a) Carbon pricing is a transfer, not a cost. The funds are returned to Ontarians. Should it not be excluded from the analysis?

b) Please describe the methodology used by Guidehouse in its analysis in terms of the traditional tests (TRC, SCT, etc.).

c) Please provide a table with a breakdown of the carbon cost included in figure 18 on page 44 for each scenario per decade and total.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) This analysis treated carbon tax as a cost that will be borne by Ontarians. This perspective is supported by a 2022 Parliamentary Budget Office Report, which concluded that most households will experience a net loss of income from the federal carbon tax, when accounting for both direct and indirect costs.[1]

b) Guidehouse did not employ cost-benefit methodologies in conducting the *Pathways to Net Zero Emissions for Ontario* study.

c) The tables below include the requested breakdown of carbon costs by decade.

Diversified Scenario

	2020	2030	2040	2050	
Carbon Emissions by Source (million tCO2e / decade)					
Renewable natural gas	0.00	0.01	0.03	0.05	/u
Biomass with CCS	0.00	0.00	0.00	-2.40	/u
Natural gas with CCS	0.00	0.27	0.64	0.75	/u
Natural gas imports	51.25	48.35	25.53	0.00	/u
Hydrogen from natural gas + CCS	0.00	0.87	1.63	1.60	/u
Carbon cost per tonne (2020$/tCO2e)	$27.50	$136.38	$138.78	$138.78	
		2020-2030	**2031-2040**	**2041-2050**	
Total Emissions Cost by Decade (2020$CAD)		$23 B	$65 B	$35 B	/u

Electrification Scenario

	2020	2030	2040	2050	
Carbon Emissions by Source (million tCO2e / decade)					
Renewable natural gas	0.00	0.00	0.02	0.02	/u
Biomass with CCS	0.00	0.00	-2.40	-4.81	
Natural gas with CCS	0.00	0.00	0.36	0.57	/u
Natural gas imports	51.25	49.28	19.19	0.00	/u
Hydrogen from natural gas + CCS	0.00	0.33	0.86	0.86	/u
Carbon cost per ton (2020$/tCO2e)	$27.50	$230.95	$235.92	$235.92	/u
		2020-2030	**2031-2040**	**2041-2050**	
Total Emissions Cost by Decade (2020$CAD)		$27 B	$108 B	$44 B	/u

[1] Office of the Parliamentary Budget Officer (2022). "A Distributional Analysis of Federal Carbon Pricing under A Healthy Environment and A Healthy Economy." Available at: https://www.pbo-dpb.ca/en/publications/RP-2122-032-S--distributional-analysis-federal-carbon-pricing-under-healthy-environment-healthy-economy--une-analyse-distributive-tarification-federale-carbone-dans-cadre-plan-un-environnement-sain-une-eco

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, 44

Preamble:

Diversified

Billion CAD, real 2020$

	2020-30	2030-40	2040-50	Total
Gas System	48	58	71	**177**
Elec. System	132	108	114	**354**
Emissions	23	66	31	**120**
End Users	19	54	41	**114**
Total	**221**	**286**	**258**	**765**

Electrification

Billion CAD, real 2020$

	2020-30	2030-40	2040-50	Total
Gas System	35	40	44	**119**
Elec. System	170	147	149	**466**
Emissions	30	115	46	**191**
End Users	15	89	66	**170**
Total	**250**	**391**	**305**	**946**

Question(s):

a) Where are RNG and fossil gas costs included in the above?

b) Please provide a live excel spreadsheet with as detailed of a breakdown of the above figures into their constituent parts as possible.

c) Where are the costs of the new hydrogen transmission and distribution costs included in the above? How much are the costs of the new hydrogen transmission and distribution infrastructure by decade and total by 2050?

Response:

The following response was provided by Guidehouse Canda Ltd.:

a) The costs associated with RNG production and conventional natural gas supply are included under "Gas System Costs".

b) Please see response at Exhibit I.1.10-GEC-20, Attachment 1 for a breakdown of cost categories into constituent parts.

c) The costs associated with new hydrogen transmission are categorized as Gas System costs. The cost of developing hydrogen transmission pipelines is provided in response at Exhibit I.1.10-GEC-20. Guidehouse declines to provide costs for distribution pipelines in Ontario because distribution pipeline costs are outside the scope of the P2NZ Study, and because a more detailed regional analysis is needed to understand how new hydrogen networks would develop depending on where demand centers develop geographically and potential opportunities for collocated supply.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, 44

Preamble:

Figure 18:

Diversified

Billion CAD, real 2020$

	2020-30	2030-40	2040-50	Total
Gas System	48	58	71	**177**
Elec. System	132	108	114	**354**
Emissions	23	66	31	**120**
End Users	19	54	41	**114**
Total	**221**	**286**	**258**	**765**

Electrification

Billion CAD, real 2020$

	2020-30	2030-40	2040-50	Total
Gas System	35	40	44	**119**
Elec. System	170	147	149	**466**
Emissions	30	115	46	**191**
End Users	15	89	66	**170**
Total	**250**	**391**	**305**	**946**

Question(s):

a) Please reproduce the above figure with cost of carbon pricing removed from the figures.

b) Please reproduce the above figure adding 2050-2070. Please do so on a best-efforts basis, making any simplifying assumptions as necessary. The purpose, in part, is to explore whether one scenario has longer-lived assets that may become more cost-effective over a longer time horizon (e.g. wind power and building retrofits, which have substantial up-front costs but produce benefits for many years).

c) Please reproduce the above figure on the assumption that fully electrified homes heating with heat pumps contribute 5 kW to the system peak from 2020 to 2040 and 4 kW from 2040 to 2050 (net of their existing, baseline contribution). Please do so on a best-efforts basis, making any simplifying assumptions as necessary. Please provide all calculations and assumptions.

d) Please reproduce the above figure on the assumption that the RNG potential in Ontario is 41 PJ and that the difference is made up by the most cost-effective alternative,

<u>Response:</u>

The following response was provided by Guidehouse Canada Ltd.:

a) The table provides a summary of scenario costs with a subtotal row that omits emissions costs. Guidehouse notes that these scenario cost results were developed using a cost optimization function that includes the carbon prices presented in Table A-2 of the P2NZ report. Guidehouse declines to re-run the Low Carbon Pathways model with a zero carbon price input, because a zero carbon price scenario is outside the scope of this analysis and because additional model runs are not feasible in the time allocated for interrogatory responses.

Table: Reproduction of P2NZ Figure 18 with Carbon Pricing Removed (Billion CAD, Real 2020$)

Diversified Scenario					**Electrification Scenario**					
	2020-2030	**2030-2040**	**2040-2050**	**TOTAL***		**2020-2030**	**2030-2040**	**2040-2050**	**TOTAL***	
Gas System	50	69	77	**197**	Gas System	40	47	45	**132**	/u
Electricity System	116	93	100	**308**	Electricity System	122	110	109	**341**	/u
End User Costs	19	32	2	**53**	End User Costs	15	51	3	**70**	/u
Subtotal	185	194	179	**558**	Subtotal	177	208	158	**543**	/u
Emissions Costs	23	65	35	**122**	Emissions Costs	27	108	44	**179**	/u
Total*	**207**	**259**	**214**	**681**	Total*	**205**	**316**	**202**	**722**	/u

* Totals may not sum exactly due to rounding

b) Guidehouse declines to answer this question, because the demand models and pathways model used for this analysis are not designed to estimate past 2050. Guidehouse notes that the Low Carbon Pathways model includes calculations to account for assets with lifetimes that extend beyond the study period. For assets with lifetimes that extend beyond the study period, the LCP model discounts the upfront capital costs associated with the buildout of new capacity based on the salvage value of assets at the end of the study period (in this case, the year 2050). The LCP model distributes these end-of-lifetime salvage discounts evenly across the asset's lifetime within the study period. Effectively, the LCP model only incurs new asset costs for the portion of the new assets' lifetime that falls within the study period.

c) Guidehouse declines to answer this question because our models are configured to estimate demand using a top-down approach and our models do not forecast demand on a building-by-building basis.

d) Guidehouse declines to answer this question because doing so would require recalibrating and rerunning the LCP model, which is out of scope for this analysis and is not feasible in the time allowed for developing interrogatory responses.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 45

Preamble:

"Electricity system costs include … new or reinforced T&D infrastructure."

"Costs for expanding and upgrading gas and electricity distribution systems (last-mile delivery) are out of scope."

Question(s):

a) Please reconcile the above two sentences as they relate to electricity distribution.

b) Please assess the cost of developing the hydrogen-only transmission and distribution pipelines required in Ontario for the scenarios

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) The analysis for the P2NZ Report includes the following costs related to electricity: electricity system interjurisdictional transmission (e.g., between ON and others), capital cost assumptions for new electric generation resources (e.g., new wind and solar) including the costs to connect those resources to the grid, the cost of operation existing electric generation facilities and electric transmission infrastructure, and the cost of new in-province electric transmission.

   The analysis for the P2NZ Report does not include the cost of new electric distribution (CAPEX or OPEX) within Ontario, the cost of electrical upgrades on a premise-by-premise basis (i.e., the analysis excludes the cost of upgrading electric circuits and breaker panels).

b) The cost of developing interregional hydrogen-only transmission pipelines and repurposing existing interregional gas pipelines to carry hydrogen is provided in response at Exhibit I.1.10-GEC-20. Guidehouse declines to provide costs for /u distribution pipelines in Ontario. Costs for upgrading methane distribution pipelines to accept hydrogen blending and for the hydrogen distribution system within Ontario are outside the scope of the P2NZ analysis and not included. This is because a more detailed regional analysis is needed to understand how new hydrogen networks would develop depending on where demand centers develop geographically and potential opportunities for collocated supply.

ENBRIDGE GAS INC.

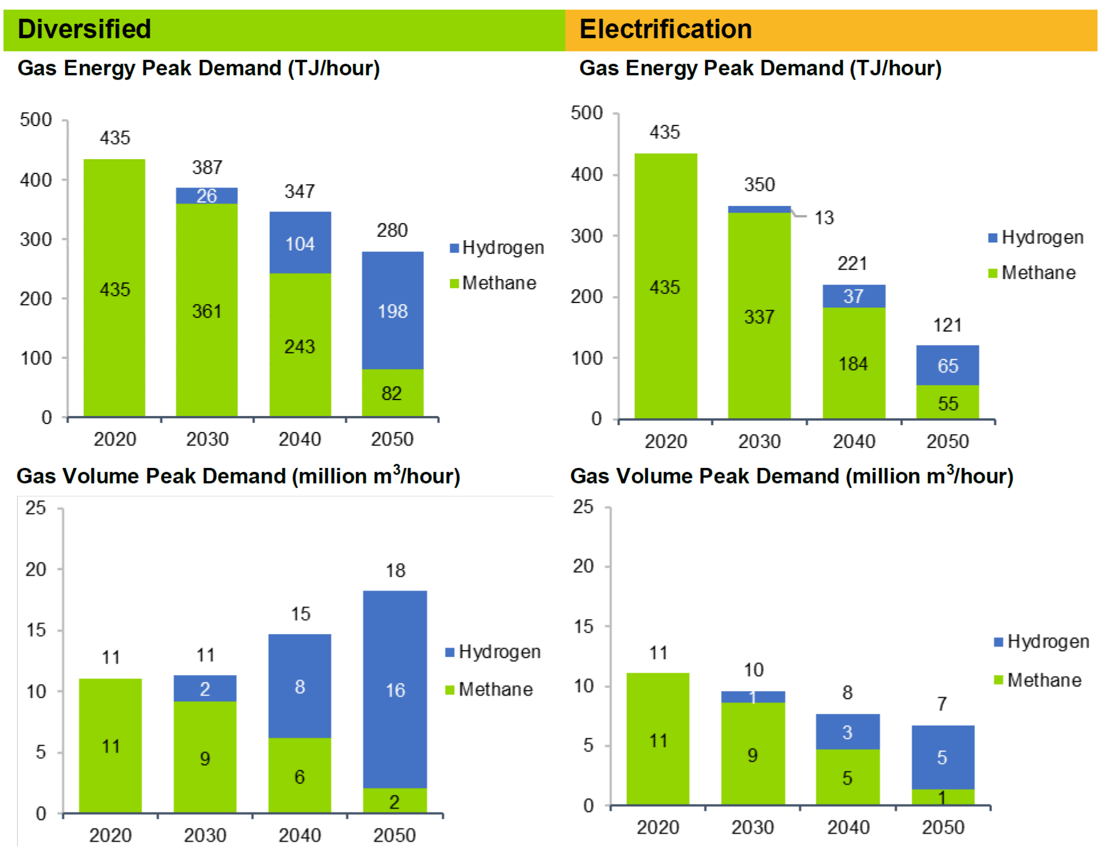
Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 38 & 44-45

Preamble:



Question(s):

This question will require assistance from Enbridge in relation to the categorization of its pipelines as between transmission and distribution pipelines.

a) Please complete the below table detailing the methane and hydrogen gas pipeline capacity requirements in each scenario, expressed in TJ/hour.

Ontario Methane and Hydrogen Pipeline Capacity Requirements (TJ/hour)				
	2020	2030	2040	2050
Gas transmission pipelines – methane only				
Gas distribution pipelines – methane only				
Gas transmission pipelines – methane & hydrogen blend				
Gas distribution pipelines – methane & hydrogen blend				
Gas transmission pipelines – dedicated hydrogen				
Gas distribution pipelines – dedicated hydrogen				

b) Please complete the below table detailing the methane and hydrogen gas pipeline capacity requirements in each scenario, expressed in million/hour.

Ontario Methane and Hydrogen Pipeline Capacity Requirements (million m3/hour)				
	2020	2030	2040	2050
Gas transmission pipelines – methane only				
Gas distribution pipelines – methane only				
Gas transmission pipelines – methane & hydrogen blend				
Gas distribution pipelines – methane & hydrogen blend				
Gas transmission pipelines – dedicated hydrogen				
Gas distribution pipelines – dedicated hydrogen				

c) Please reproduce the table in (b), indicating in brackets in each cell which pipelines are included in the Guidehouse cost estimates and which are not.

d) Please make best efforts to estimate the gas pipeline costs that are not already included in the Guidehouse analysis, including, if applicable, the cost to build a new hydrogen distribution system.

e) Please complete the below table detailing the methane and hydrogen gas pipeline requirements in each scenario, expressed in kms.

Ontario Methane and Hydrogen Pipeline Length Requirements (km)				
	2020	2030	2040	2050
Gas transmission pipelines – methane only				
Gas distribution pipelines – methane only				
Gas transmission pipelines – methane & hydrogen blend				
Gas distribution pipelines – methane & hydrogen blend				
Gas transmission pipelines – dedicated hydrogen				
Gas distribution pipelines – dedicated hydrogen				

Response:

The following response was provided by Guidehouse Canada Ltd.:

The P2NZ study used a high-level approach to analyze future capacity needs on a province-wide scale. The scope of the P2NZ study was not sufficiently granular to estimate intra-regional distribution. As such, the tables below present Guidehouse's estimates of province wide gas network capacity and do not distinguish between transmission and distribution capacity.

The values provided in this response represent Ontario-wide estimates developed in the P2NZ study to study the cost of Ontario's energy transition. The values provided in this response are not reflective of the current or future planned capacities of Enbridge Gas Inc.'s gas transmission or distribution systems.

a) Please see the tables below, Table 1 for the Diversified Scenario, and Table 2 for the Electrification Scenario

Table 1
Diversified Scenario Gas Pipeline Capacity Requirements

Ontario Methane and Hydrogen Pipeline Capacity Requirements (TJ/hour)					
	2020	2030	2040	2050	
Gas system capacity requirements – methane only	437	356	-	-	/u
Gas system capacity requirements – methane & hydrogen blend	-	-	260	87	/u
Gas system capacity requirements – dedicated hydrogen	0	26	105	198	/u

Table 2
Electrification Scenario Gas Pipeline Capacity Requirements

Ontario Methane and Hydrogen Pipeline Capacity Requirements (TJ/hour)					
	2020	2030	2040	2050	
Gas system capacity requirements – methane only	437	332	-	-	/u
Gas system capacity requirements – methane & hydrogen blend	-	-	185	56	/u
Gas system capacity requirements – dedicated hydrogen	0	13	37	62	/u

b) Please see the tables below, Table 3 for the Diversified Scenario, and Table 4 for the Electrification Scenario.

Table 3
Diversified Scenario Gas Pipeline Capacity Requirements

Ontario Methane and Hydrogen Pipeline Capacity Requirements (million m3/hour)					
	2020	2030	2040	2050	
Gas system capacity requirements – methane only	11.2	9.2	-	-	/u
Gas system capacity requirements – methane & hydrogen blend	-	-	6.7	2.2	/u
Gas system capacity requirements – dedicated hydrogen	-	2.1	8.7	16.3	/u

Table 4
Electrification Scenario Gas Pipeline Capacity Requirements

Ontario Methane and Hydrogen Pipeline Capacity Requirements (million m3/hour)					
	2020	2030	2040	2050	
Gas system capacity requirements – methane only	11.2	8.5	-	-	/u
Gas system capacity requirements – methane & hydrogen blend	-	-	4.8	1.5	/u
Gas system capacity requirements – dedicated hydrogen	-	1.0	3.0	5.1	/u

c) Please see table below.

Table 5
Ontario Methane and Hydrogen Pipeline Capacity Requirements

	2020-2050
Gas transmission pipelines – methane only	Existing and incremental new pipelines are included (though the modeling shows the Diversified and Electrification scenarios would not need new methane transmission pipeline)
Gas distribution pipelines – methane only	Existing pipelines are included; Incremental new pipelines are not included
Gas transmission pipelines – methane & hydrogen blend	None exist today. Conversion of existing methane pipelines is included
Gas distribution pipelines – methane & hydrogen blend	Existing and incremental new pipelines are not included
Gas transmission pipelines – dedicated hydrogen	Existing and incremental new pipelines are included
Gas distribution pipelines – dedicated hydrogen	Existing and incremental new pipelines are not included

d) Guidehouse declines to answer this question because a more detailed regional analysis is needed to understand how new hydrogen networks would develop depending on projections of regional demand centers and potential opportunities for collocating supply with demand. Guidehouse notes that the P2NZ cost analysis also excludes investments in the electricity distribution system.

e) Guidehouse declines to provide lengths of in-province transmission and distribution pipeline, because Guidehouse modeled the costs of in-province pipelines on a capacity basis. Please reference Exhibit I.1.10-GEC-24(h) for lengths of interregional gas pipelines.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 38 & 44-45

Question(s):

These questions are primarily for Enbridge:

a) Enbridge describes its gas peak demand as 11 million m3/hour. What is the peak capacity of Enbridge's gas system, expressed in million m3/hour?

b) What is the total capital cost of Enbridge's pipeline system in Ontario expressed as $ per million m3/hour of capacity?

c) What is the levelized cost of Enbridge's pipeline system in Ontario, including capital and operating costs, expressed as $ per million m3/hour of capacity?

Response:

a-c) The capacity of the Enbridge Gas system, and calculations which include the capacity, cannot be provided because the gas system is complex and interconnected. Capacity is influenced by a variety of factors, including different pressure subsystems, stations, new customer attachments, existing customer demand changes and the locations of these changes. The assessment of Enbridge Gas's system to adequately supply the needs of its customers is done through load capture, demand forecasts, and complex hydraulic models. The hydraulic models contain not only the demands but also the locations of these demands and the pipes that serve them. This allows for the assessment of the health of the model, specifically in its ability to serve the volume and pressure required. The capacity for any system to accept new demands is dependent on the location, volume, and pressure required. As a result, there is a multitude of scenarios and varying results for each subsystem dependent on where the capacity is assessed. Please see response at Exhibit I.1.10-GEC-57 for the referenced peak gas demand.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 38 & 44-45

Question(s):

a) This question is for Guidehouse: Please provide a table showing the annual cost for Ontario gas transmission and distribution in each scenario from 2020 to 2050.

b) This question is for Enbridge: Please provide the response to (a) and derive the implied annual revenue requirement.

Response:

a)The following response was provided by Guidehouse Canada Ltd.:

Guidehouse calculated the costs of gas transmission on a decade basis and cannot provide costs on an annual basis as requested. Response at Exhibit I.1.10-GEC-20, Attachment 1 provides the costs of new hydrogen transmission pipeline, which include both the capital and operating costs of interprovince and intraprovince transmissions systems. Note that there are no new capital investments in natural gas transmission pipelines in either scenario.

The costs of gas distribution system expansion and conversion were outside the scope of the P2NZ study and are not provided.

The costs presented in response at Exhibit I.1.10-GEC-20, Attachment 1 are based on estimates of O&M costs developed by Guidehouse and Guidehouse's independent estimate of future gas network capacity specific to the scenarios analyzed in the P2NZ report. The capacity and cost estimates do not represent gas system capacity forecasts developed by Enbridge Gas Inc.

b) Enbridge Gas declines to provide a response. As stated in the response to part a) above, the costs presented are based on estimates developed by Guidehouse that represent an estimate of the total investments required in the pipeline system in Ontario. There is no distinction between what investments could be made by

Enbridge Gas versus other parties, such as low-carbon fuel suppliers, and distribution system costs are not included in the cost estimates. It is therefore not possible to determine Enbridge Gas's implied revenue requirement.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2

Preamble:

Per the Ontario Association of Fire Chiefs: “More than 50 people die each year from carbon monoxide poisoning in Canada, including 11 on average in Ontario.”

Question(s):

a) Does Guidehouse agree that a decarbonization pathway that involves fully electrifying homes in Ontario could save approximately 11 lives each year by preventing carbon monoxide poisoning from homes? If not, please provide the estimated lives saved in a decarbonization pathway that involves full electrification of space and water heating through avoided carbon monoxide poisoning

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Guidehouse did not model the health impacts resulting from residential building electrification. The modeling of health impacts is outside the scope of the *Pathways to Net Zero Emissions for Ontario* Study

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Issue:

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2, A-10

Preamble:

“Gas Heat Pump with A/C Unit [CAD$/unit] $12,200”

Question(s):

a) Guidehouse’s estimate for a gas heat pump originates from Enbridge. Please independently estimate the cost of a gas heat pump and provide the results.

b) Please provide a list of Gas Heat Pumps available on the market in Ontario, the price (equipment and install), the seasonal COP, and the COP at -20°C.

c) Please provide a list of Gas Heat Pumps available on the market in the United States, the price (equipment and install, converted to CAD), and seasonal COP, and the COP at °C

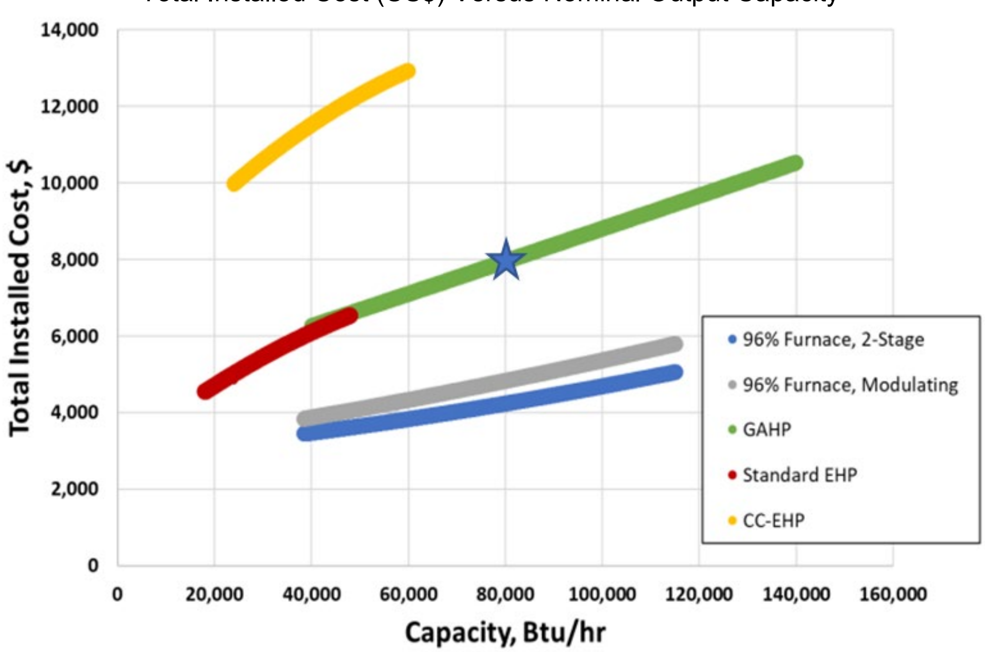
Response:

The following response was provided by Guidehouse Canada Ltd.:

a) In Table 4 of the P2NZ report provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, Guidehouse presents an assumption of $12,200 for a gas heat pump with low-capacity air conditioning unit. This cost estimate was determined based on a cost curve provided by Stone Mountain Technologies, Inc., a manufacturer of gas heat pumps.[1] This cost curve is reproduced below, with a point indicating the total installed cost assumed in the P2NZ study for a USD$8,000 (CAD$10,800) gas heat pump. Guidehouse assumed the gas heat pump installation may be accompanied by multiple room A/C units for total cost of $12,200.

[1] Stone Mountain Technologies Inc. (2021). “Gas Absorption Heat Pumps.” Filed in 2021-11-15, EB-2021-0002, Exhibit I.10i.EGI.CCC.40, Attachment 1, p.10 of 160. Available at: https://www.rds.oeb.ca/CMWebDrawer/Record/732115/File/document.

Figure: Residential Forced-Air Heating Installed Costs.
Total Installed Cost (US$) Versus Nominal Output Capacity[1]



To confirm the reasonableness of this estimate, Guidehouse met with a gas heat pump manufacturer and discussed their commercialization and market entry plans. Guidehouse also reviewed a technology summary from the US DOE[2] and a technology briefing from GTI.[3]

b-c) Guidehouse has not independently compiled a list of gas heat pump models available in the US/Canada, and Guidehouse has not independently attempted to procure and install gas heat pumps in Ontario. Guidehouse referred to a 2019 Gas Technology Institute industry roadmap, which indicates that several manufacturers have commercially available gas heat pump products in the US and Canada.[4] In addition to manufacturers with available product, the roadmap also indicates that several other manufacturers are in the pre-commercial stage and expect to introduce gas heat pump products to market in the next 1-5 years. Figure 2 of the roadmap indicates that residential gas heat pumps from Robur have an efficiency rating of 129% AFUE, and commercial gas heat pumps from Yanmar and Intellichoice have COP_gas ratings of 1.3 to 1.4. Guidehouse declines to provide the COP at various temperatures for these models because Guidehouse has not compiled performance curves for these models.

[2] https://www.energy.gov/eere/buildings/articles/rd-opportunities-natural-gas-technologies-building-applications.
[3] https://www.ilsag.info/wp-content/uploads/Gas_Tech_Innovations-GTI_ILSAG_09-17-19.pdf
[4] GTI and Brio (2019). "The Gas Heat Pump Technology and Market Roadmap: Industry White Paper." Figures 2-3. Available at: https://www.gti.energy/wp-content/uploads/2020/09/Gas-Heat-Pump-Roadmap-Industry-White-Paper_Nov2019.pdf.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2

Question(s):

a) Please provide a map of Ontario showing the location of industrial facilities that require a high-grade heat that cannot be electrified.

b) Please provide any reports or analysis comparing the cost-effectiveness of on-site or local electrolysers versus green hydrogen delivered by a dedicated pipeline system for that purpose.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) This *Pathways to Net Zero Emissions for Ontario* Study was conducted at a high level, with assumptions about electrification potential for different sub-sector industries based on the proportion of industrial energy used for different purposes (e.g., energy used for HVAC, process heat, etc.). The analysis did not map individual or consider energy usage on an individual customer basis.

b) Guidehouse did not conduct a cost comparison regarding the geographic location of electrolyzers. Such a cost comparison would involve analysis at a sub-provincial granularity that was outside the scope of this study.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2

Question(s):

Please respond to the following comments on the Guidehouse report:

a) The Guidehouse report does not study or assess the cost for a full electrification scenario wherein (i) investment in province-wide pipeline infrastructure is reduced over time to zero, (ii) hard-to-electrify sectors convert to hydrogen via as on-site electrolyser, a nearby electrolyser (e.g. with short-distance distribution), storage, and/or trucked fuel, (iii) the remaining sectors electrify, and (iv) cost-effective methods are adopted to decrease peak and annual electricity resource requirements (e.g. thermal storage, V2G/B, etc.).

b) The Guidehouse analysis does not extend beyond 2050 to account for the benefits of investments with long-lived benefit streams. It therefore is biased against investments with significant up-front costs that have a stream of future benefits with low or no ongoing costs. Those include, for example: building envelope energy efficiency, wind power, solar power, investments in electricity transmission and distribution infrastructure.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) This statement does not contain a question. Guidehouse confirms that the *Pathways to Net Zero Emissions for Ontario* Study does not examine a scenario wherein investment in province-wide pipeline infrastructure is reduced over time to zero.

   Guidehouse did not conduct a cost comparison regarding the geographic location of electrolyzers. This involves analysis at a sub-provincial granularity that was outside the scope of this study, and a regional study that maps potential hydrogen hubs would be useful to test the most economical approach to hydrogen network development. In a prior study of hydrogen network development in the European

Union,[1] Guidehouse found that it can be more cost effective to co-locate green hydrogen production with renewable energy generation and transmit hydrogen to demand centers, rather than transmitting electricity to on-site hydrogen generation.

Guidehouse did model cost effective methods to reduce peak load in both scenarios. For example, Guidehouse implicitly accounted for the impact of demand response in the transportation sector when developing the demand forecasts. Guidehouse estimated that the managed charging of electric vehicles will be an impactful demand response measure that will shape the hourly electric load profile of the transportation sector. To implicitly account for the impact of demand response, the analysis used separate electric load shapes for the buildings and transportation sectors that do not have coincident peaks.

b) This statement does not contain a question and Guidehouse does not confirm the statement. The Low Carbon Pathways model includes calculations to account for assets with lifetimes that extend beyond the study period. For assets with lifetimes that extend beyond the study period, the LCP model discounts the upfront capital costs associated with the buildout of new capacity based on the salvage value of assets at the end of the study period (in this case, the year 2050). The model distributes these end-of-lifetime salvage discounts evenly across the asset's lifetime within the study period. Effectively, the LCP model only incurs new asset costs for the portion of the new assets' lifetime that falls within the study period.

[1] Guidehouse (2022). "European Hydrogen Backbone." Available at: https://ehb.eu/files/downloads/ehb-report-220428-17h00-interactive-1.pdf

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

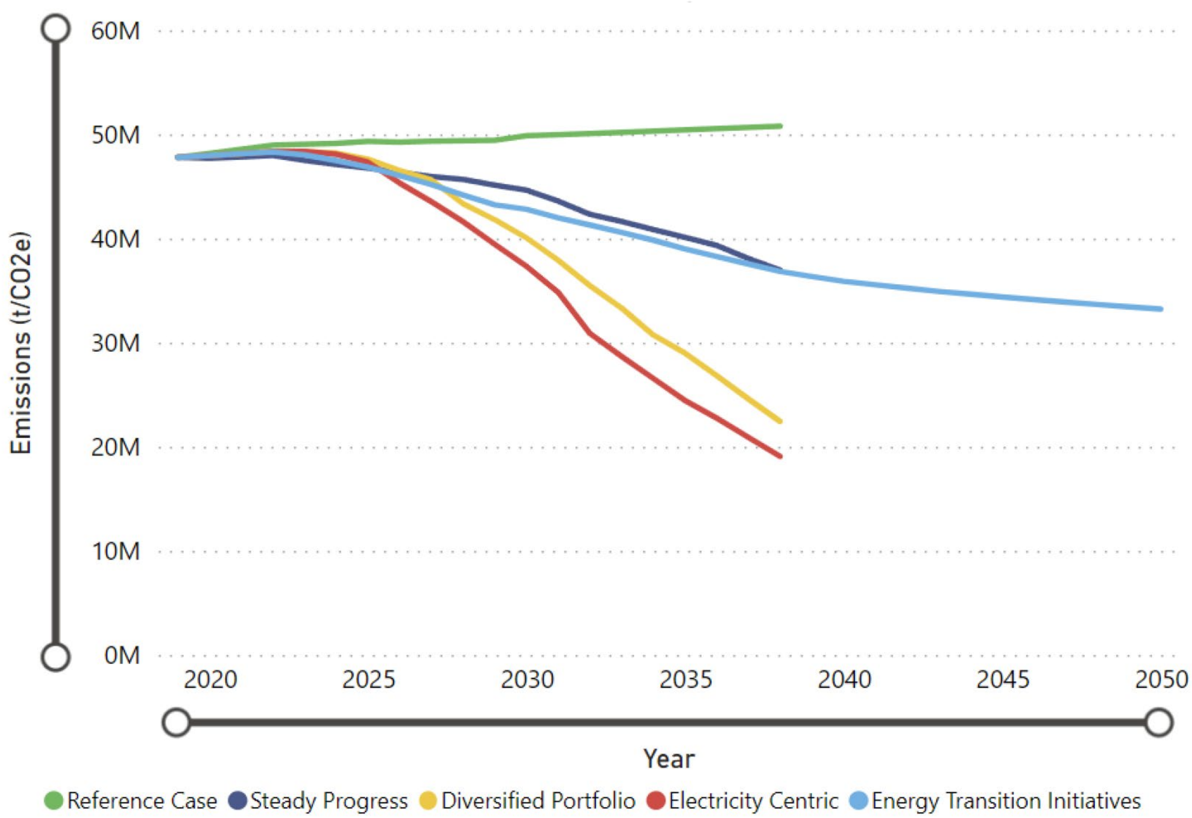
Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 6, Attachment 1, p. 23

Preamble:

Exhibit 17 – All Scenarios GHG Emissions (t/CO_2e)



Question(s):

a) This question is for the Posterity Group: Please reproduce the above figure including full lifecycle emissions, including upstream emissions (e.g. from fossil-fuel-based hydrogen, transmission methane leaks, etc.) and methane leaks from customer equipment. Please make and state your assumptions for those.

For upstream emissions from fossil-fuel-based hydrogen, please use the figures found in the following peer-reviewed report or justify a decision to use different figures: Robert W. Howarth and Mark Z. Jackson, "*How green is blue hydrogen?" Energy Science & Engineering,* 26 July 2021 (link).

For the emissions of unburned methane from customer equipment, please use the figures found in the following peer-reviewed report or justify a decision to use different figures: Zachary Merrin and Paul W. Francisco, *Unburned Methane Emissions from Residential Natural Gas Appliances* (link).

Response:

The following response was provided by Posterity Group:

a) Please see response at Exhibit I.1.10-ED-21.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5

Question(s):

a) Please provide the cost for the (i) Guidehouse report; (ii) Posterity Group, June 23, 2022 report, and (iii) Posterity Group, September 22, 2022 report.

b) Please confirm if the above costs are covered by ratepayers and what account they are attributed to.

Response:

a-b) Please see response at Exhibit I.1.2-CCC-3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5

Question(s):

a) Natural Resources Canada provides the following Natural Gas Conversions:

Approximate Natural Gas Conversions				
	‹- Multiply by -›			
	m^3	cf	MMBtu	GJ
Cubic Metres (m^3)		35.301	0.0353	0.0373
Cubic Feet (cf)	0.0283		0.001	0.001055
Million British thermal units (MMBtu)	28.3278	1000		1.0551
Gigajoules (GJ)	26.853	947.817	0.9478	

For example, to convert from 1 MMBtu to Gigajoules, multiply by 1.055.[1]

Please confirm whether Enbridge believes those conversion rates are (i) accurate and ii) the same as the conversion rates used in its application. If not, please (i) reproduce the table with the rates that Enbridge used for its application and (ii) provide the rates that Enbridge believes are accurate.

b) Please provide the following figures and conversion factors:

i. tCO2e/m3 methane gas (combustion, Ontario)
ii. m3 of hydrogen with the equivalent energy of 1 m3 of methane gas
iii. $/m3 hydrogen to equivalent of $/m3 methane gas (i.e. equivalent energy content)
iv. 1 kg hydrogen to 1 m3 hydrogen
v. 1 kg hydrogen to 1 J hydrogen
vi. $/kg hydrogen to $/m3 hydrogen

c) Please complete the following conversion tables.

[1] https://www.nrcan.gc.ca/energy/energy-sources-distribution/natural-gas/natural-gas-primer/5641

Watt and Joules				
	‹- Multiply by -›			
	J	**PJ**	**GJ**	**TJ**
kW				
MW				
GW				

Watt and Joules - Hourly				
	‹- Multiply by -›			
	J/hr	**PJ/hr**	**GJ/hr**	**TJ/hr**
kWh				
MWh				
GWh				

Watts and Joules - Price				
	‹- Multiply by -›			
	$/J	**$/PJ**	**$/GJ**	**$/TJ**
$/kWh				
$/MWh				
$/GWh				

Methane Gas – Energy and Volume				
	‹- Multiply by -›			
	J	**PJ**	**GJ**	**TJ**
m3				
million m3				

Methane Gas Peak Demand Conversion Factors				
	‹- Multiply by -›			
	J/hr	**PJ/hr**	**GJ/hr**	**TJ/hr**
m3/hour				
million m3/hour				

Methane Gas - Price				
	‹- Multiply by -›			
	$/J	**$/PJ**	**$/GJ**	**$/TJ**
$/m3				
$/million m3				

Hydrogen Gas – Energy and Volume				
	‹- Multiply by -›			
	J	**PJ**	**GJ**	**TJ**
m3				
million m3				

Hydrogen Gas Peak Demand Conversion Factors				
	‹- Multiply by -›			
	J/hr	**PJ/hr**	**GJ/hr**	**TJ/hr**
m3/hour				
million m3/hour				

Hydrogen Gas - Price				
	‹- Multiply by -›			
	$/J	**$/PJ**	**$/GJ**	**$/TJ**
$/m3				
$/million m3				

Response:

a) The Natural Resources Canada conversion rate table provided in the question is replicated as Table 1, with amendments provided below. The remaining conversion rates (without notes) are the same as the original table provided in the question.

Table 1
Approximate Natural Gas Conversions

	‹- Multiply by -›			
	m3	cf	MMBtu	GJ
Cubic Metres (m3)		35.315(5)	0.03702 (4)	0.03908 (1)
Cubic Feet (cf)	0.0283		0.00105 (3)	0.00111 (2)
Million British thermal units (MMBtu)	27.012 (4)	953.94 (3)		1.0551
Gigajoules (GJ)	25.58854 (1)	903.65 (2)	0.9478	

Notes:

(1) The values for the conversions between GJ and cubic metres have been updated to reflect the heat value of natural gas specified in this Application: 38.86 MJ/m3 or 39.08MJ/m3 are used for Enbridge Gas North or Enbridge Gas South zones, respectively as provided at Exhibit 3, Tab 6, Schedule 1 paragraph 3). For simplicity, only the 39.08MJ/m3 value is used.

(2) Updated conversion rate between cubic feet and GJ as a result of the updated heat values in note (1).

(3) Updated conversion rate between cubic feet and MMBtu as a result of the updated heat values in note (1).

(4) Updated conversion rate between cubic metres and MMBtu as a result of the updated heat values in note (1).

(5) The conversion rate between cubic metres and cubic feet was incorrectly recorded in the original table provided in the question as 35.301; the correct value is 35.315, as sourced from the CER website in footnote 3.

b) The following conversions are provided in response:

i. The Ontario combustion conversion for 1m^3 of natural gas to tonnes of carbon dioxide equivalent (tCO2e) emissions is 0.001932 tCO2e/m3 of residential/commercial marketable natural gas[2].

ii. Please see response at Exhibit I.4.2-ED-127.

iii. On a pure energy basis equivalency only with energy sold in GJ, a conversion of energy values regardless of cost for: 1 m^3 of hydrogen ≈ 0.0127 GJ of hydrogen. The relevancy would be the unit cost of one of the energy carriers. For hydrogen, it is necessary to know the delivered cost of hydrogen to provide a cost for the equivalent amount of energy contained in 1 m^3 of natural gas. This will be different for hydrogen producers as there is currently no standard pricing as with natural gas. Natural gas on a volumetric basis has approximately 3X the volumetric energy density of hydrogen.

This cost for hydrogen on an energy equivalency basis is not comparable to the cost of natural gas. Natural gas is currently produced at scale, well established, has a mature distribution system and must meet a singular requirement for pipeline grade quality. Conversely hydrogen for blending (renewable or low carbon hydrogen) is not at scale and can be produced in several ways, different grades and purity. For each variant, the cost would be different.

iv. 1 kg of hydrogen is ~11.126 Nm^3 of hydrogen (Nm^3 gas measured at 0°C and 101.325 kPaa) or ~11.9 sm^3 of hydrogen (sm^3 gas measured at 15°C and 1 atm)

v. Using the HHV for hydrogen: 1 kg of H_2 ≈ 141,900,000 J H_2
Using the LHV for hydrogen: 1 kg of H_2 ≈ 120,000,000 J H_2

vi. To convert from $/kg of hydrogen to $/m3, a price could be applied to the conversion factors in part iv. Considering the uncertainty in market prices no assumed price is available.

c) For tables entitled “Watt and Joules”, “Watt and Joules – Hourly", Watts and Joules - Price, the conversion seeks to convert power to energy or energy to power, which cannot be done.

For the tables titled “Methane Gas” Enbridge Gas is unable to provide conversion rates as Enbridge Gas does not distribute pure methane gas. As an alternative, for conversion rates related to natural gas, hydrogen and other fuels, Enbridge Gas

[2] Environment and Climate Change Canada. (2022, April 14). 2022 National Inventory Report 1990-2020: Greenhouse Gas Sources and Sinks in Canada. Part 2. Table A6.1-1 and Table A6.1-3. https://unfccc.int/documents/461919

provides a reference to the Canada Energy Regulator's "Energy Conversion Tables" website. [3]

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[3] Canada Energy Regulator. Energy conversion tables. https://apps.cer-rec.gc.ca/Conversion/conversion-tables.aspx?GoCTemplateCulture=en-CA#2-6

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2

Question(s):

This question is for Guidehouse:

a) For the day corresponding to the winter peak demand, please provide the (i) peak hour demand (MW) for that peak day and (ii) the average hourly demand for that peak day. Please provide those figures for 2020, 2030, 2040, and 2050. Please make and state any simplifying assumptions as necessary to answer the question and state any caveats.

b) For an air-source heat pump, what is the difference between the peak hour demand on the peak winter day and the average hourly demand on the peak winter day? Please provide the underlying calculations.

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Hourly winter peak electric loads by scenario and by decade are provided in Attachment 1. Table 1 provides the winter peak hours and the peak hour electric demand by scenario and decade. Note that in the Electrification scenario, the peak hour shifts to the morning due to building heating electrification. In the Diversified scenario, the peak also shifts to the morning in 2040 due to building heating /u
electrification, but then shifts to the evening in 2050 due to transportation /u
electrification resulting in evening charging since there is less building heating /u
electrification.

Table 1
Winter Peak Hour Electric Demand

Scenario	Decade	Hour Ending	Peak Hour Demand (MW)	Average Peak Day Demand (MW)	
Diversified	2020	18:00	21,525	19,333	
	2030	19:00	32,421	30,331	/u
	2040	8:00	42,565	40,093	/u
	2050	19:00	51,057	47,708	/u
Electrification	2020	18:00	21,525	19,333	
	2030	8:00	37,965	35,252	/u
	2040	8:00	68,283	62,550	/u
	2050	8:00	82,143	76,553	/u

b) Guidehouse declines to answer this question because Guidehouse used a top-down approach to energy modeling in the Pathways *to Net-Zero Emissions for Ontario* Study, and the study did not model the electric consumption or coincident peak demand of individual buildings or individual heat pump systems.

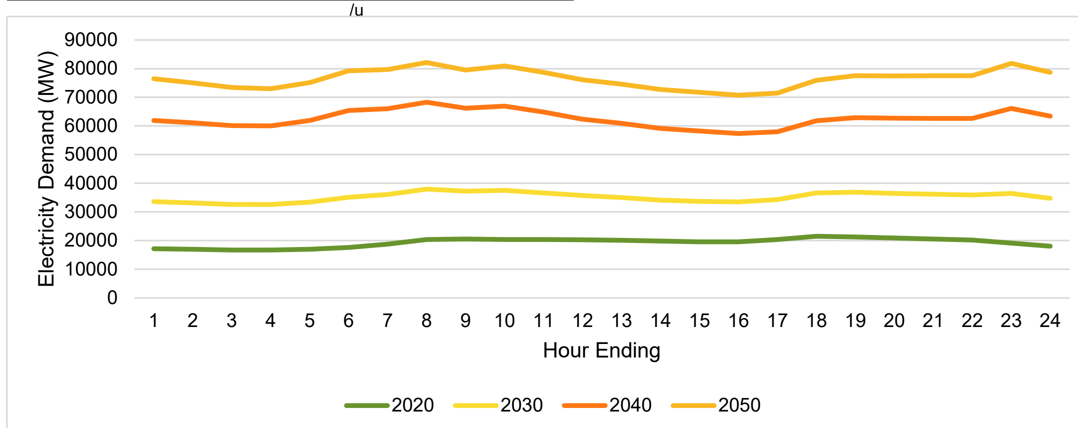
Ontario Winter Peak Day Loadshapes

Timestep	2020	2030	2040	2050	
1	17163	33642	61955	76512	/u
2	17017	33188	61154	75061	/u
3	16744	32630	60163	73456	/u
4	16722	32596	60024	72980	/u
5	16969	33439	61919	75139	/u
6	17590	35130	65434	79210	/u
7	18773	36090	65985	79653	/u
8	20360	37965	68283	82143	/u
9	20534	37249	66226	79495	/u
10	20369	37496	66943	80907	/u
11	20364	36676	64832	78701	/u
12	20304	35752	62406	76123	/u
13	20103	35052	60955	74634	/u
14	19838	34169	59118	72706	/u
15	19533	33657	58219	71759	/u
16	19584	33490	57362	70745	/u
17	20356	34359	57944	71465	/u
18	21525	36647	61792	75957	/u
19	21274	36905	62917	77547	/u
20	20875	36503	62705	77479	/u
21	20574	36218	62628	77521	/u
22	20176	35933	62662	77585	/u
23	19163	36498	66108	81811	/u
24	18090	34753	63457	78689	/u
Average	*19333*	*35252*	*62550*	*76553*	/u

Winter Peak Hour by Decade

Decade	Hour	Peak Demand (MW)	Average Daily Demand (MW)	
2020	18	21525	19333	
2030	8	37965	35252	/u
2040	8	68283	62550	/u
2050	8	82143	76553	/u

/u



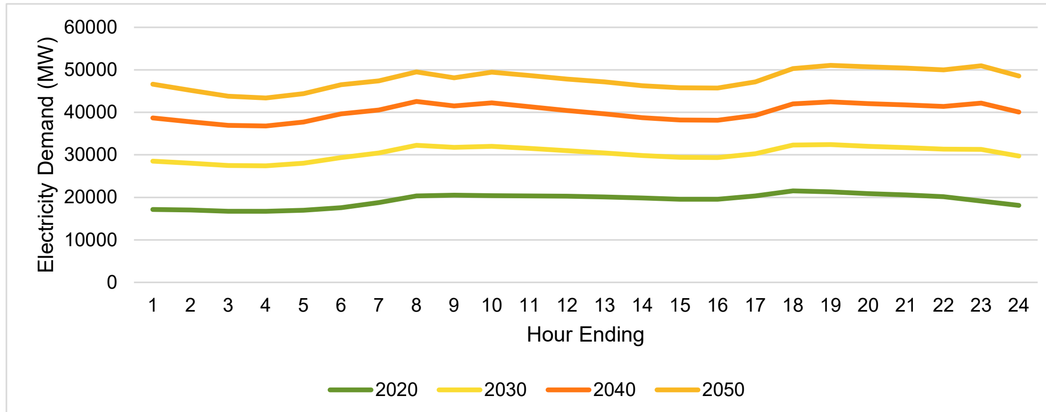
Ontario Winter Peak Day Loadshapes

Timestep	2020	2030	2040	2050	
1	17163	28526	38667	46602	/u
2	17017	28039	37809	45166	/u
3	16744	27491	36947	43807	/u
4	16722	27420	36794	43381	/u
5	16969	28053	37725	44380	/u
6	17590	29383	39635	46504	/u
7	18773	30429	40572	47415	/u
8	20360	32232	42565	49530	/u
9	20534	31755	41513	48120	/u
10	20369	32020	42217	49436	/u
11	20364	31527	41347	48669	/u
12	20304	30961	40409	47840	/u
13	20103	30468	39675	47176	/u
14	19838	29827	38729	46281	/u
15	19533	29410	38223	45800	/u
16	19584	29362	38138	45741	/u
17	20356	30289	39282	47138	/u
18	21525	32284	42020	50289	/u
19	21274	32421	42496	51057	/u
20	20875	32011	42069	50693	/u
21	20574	31702	41749	50412	/u
22	20176	31333	41397	50007	/u
23	19163	31304	42166	50986	/u
24	18090	29699	40087	48569	/u
Average	*19333*	*30331*	*40093*	*47708*	/u

Winter Peak Hour by Decade

Decade	Hour	Peak Demand (MW)	Average Daily Demand (MW)	
2020	18	21525	19333	
2030	19	32421	30331	/u
2040	8	42565	40093	/u
2050	19	51057	47708	/u

/u



ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 5, Attachment 2

Question(s):

These questions are for Guidehouse:

a) Does Guidehouse agree that the cost of green hydrogen depends on the cost of net-zero power?

b) What does Guidehouse assume for the cost of green hydrogen in 2050 ($/PJ)? Please provide a copy of or link to the study or report that serves as the basis for this assumption. Please indicate the cost of net-zero power ($/MWh, levelized) assumed in that study or report used to generate the green hydrogen at the relevant price point?

c) What does Guidehouse assume for the average and marginal cost of net-zero power ($/MWh, levelized) in 2050 in its modelling?

Response:

The following response was provided by Guidehouse Canada Ltd.:

a) Guidehouse agrees that the cost of green hydrogen depends on the cost of net-zero power.

b-c) Guidehouse declines to answer this question because the *Pathways to Net Zero Emissions for Ontario* Study did not forecast a market price for green hydrogen. The purpose of the *Pathways* study was to assess economy-wide costs of different approaches to achieving net-zero GHG emissions in Ontario by 2050.

The study assessed economy-wide costs that would be incurred to construct and operate the zero emissions electricity generation resources (e.g., solar and wind power) and the hydrogen production resources (e.g., electrolyzers) needed to produce sufficient hydrogen to meet demand in the future.

The Guidehouse Low Carbon Pathways model accounts for hour-to-hour changes in hydrogen demand, the electricity supply mix, periods of surplus electricity generation, and other factors. The impacts of all these factors are modelled endogenously to estimate the total electric and hydrogen generation capacity required to meet Ontario's future energy demand in different scenarios. However, the study did not attempt to isolate the cost of green hydrogen production from the economy-wide analysis.

Similarly, when assessing the cost of net-zero power generation, the *Pathways* analysis estimated the capital and operating costs of producing electricity from renewable sources to assess costs on an economy-wide scale, but the study did not estimate the levelized cost of net-zero power.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 2, p. 2; Exhibit 1, Tab 10, Schedule 5, p. 22

Preamble:

Question(s):

a) Enbridge states that: “an electrification pathway to net-zero will require massive investment in new electrical generation, transmission, storage and distribution systems, and end user equipment.” If all homes in Ontario were fully electrified with heat pumps, how much could the peak winter demand (MW) be reduced through electric thermal storage units (e.g. those from SSi Energy, Stash, and Steffes)[1]?

b) Please describe the incentives available for Electric Thermal Storage in Quebec, Nova Scotia, and PEI.

c) Enbridge states that: “an electrification pathway to net-zero will require massive investment in new electrical generation, transmission, storage and distribution systems, and end user equipment.” If all homes in Ontario were fully electrified with heat pumps, how much could the peak winter demand (MW) be reduced through V2G/B technology?

Response:

a),c) Enbridge Gas undertook the Pathways to Net-Zero Emissions for Ontario Study provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, to examine two different, but plausible, pathways to achieve net-zero in Ontario, including the role that low and zero carbon fuels could play in combination with low emitting electricity in achieving net-zero emissions. As the energy transition unfolds, there will be many technologies that could be leveraged along a pathway toward a net-zero economy. Due to cost and time constraints, it was not possible to model every possible permutation of how net-zero could be achieved in Ontario, or to consider every type of technology that may be used in the future.

[1] See https://www.ssie.ca/products/, https://stash.energy/en/product/, and https://www.steffes.com/ets/comfort-plus-forced-air/.

The referenced technologies were not included in the P2NZ Study and, therefore, Enbridge Gas cannot speculate on how the peak winter electricity demand might change resulting from the use of the referenced technologies.

b) Enbridge Gas is not familiar with the incentives available in other jurisdictions regarding the referenced technologies and, therefore, declines to describe them here.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, Page 20, 3.4. Rate Setting, Paragraph 60

Preamble:

"Enbridge Gas is proposing a straight fixed variable with demand (SFVD) rate design to be used for the proposed harmonized general service customer classes. SFVD rate design consists of a customer charge and a demand charge which matches the cost to provide delivery service to each customer by reflecting the demand that each customer imposes on the network and the cost of being connected to the network".

Question(s):

Does SFVD significantly reduce EGI volume risk? If so, why is EGI stating volume risk is increasing.

Response:

The statement about exacerbated volumetric risk provided at Exhibit 1, Tab 10, Schedule 4, page 19, part c) was not meant to be narrow and specific to declining volumetric end-use consumption, but should rather be interpreted as including the risk of customers leaving the system, new customers not attaching to the system in favor of another energy source, as well as, the risk of declining volumetric consumption, and potentially declining peak day demand.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, Page 20, Paragraphs 60-62

Question(s):

a) How many gas and electric utilities in Canada have straight fixed variable with demand (SFVD) rate design? Please list these.

b) How many US gas and electric utilities have straight fixed variable with demand (SFVD) rate design? Please list these with and indicate the States served.

c) For each of Union and EGI please indicate how much of fixed costs are included in the customer charge and how much in consumption?

d) For each of Union and EGI please indicate how much of fixed costs are included in the customer charge and how much in the proposed demand charge?

e) Does not SFVD reduce the risks of recovery of fixed costs?

f) Comment if this would lead to a lower Equity Ratio - other factors not considered?

Response:

a-d) This issue will be addressed in Phase 2 of the proceeding in accordance with the OEB's Decision on Issues List dated January 27, 2023.

e-f) As provided at Exhibit 8, Tab 2, Schedule 3, the Straight Fixed Variable with Demand (SFVD) rate design recovers fixed costs through fixed charges. The fixed customer-related costs are recovered in the monthly customer charge, the capacity or demand-related costs are recovered in a monthly demand charge, and variable costs are recovered in volumetric charges.

The recovery of fixed customer-related and demand-related costs in fixed charges results in less recovery risk in delivery charges due to weather and average use variances compared to the current rate design. The Company's delivery revenue is subject to an average use true up mechanism, but there is currently no true up for weather variances. As a result, the current rate design may result in lower or higher delivery revenue than the SFVD rate design due to weather variances caused by warmer or colder weather.

There are no proposed changes to Enbridge Gas's equity thickness due to the proposed SFVD rate design, consistent with the approach for Ontario electric utilities. At Exhibit 8, Tab 2, Schedule 3, page 14, paragraph 41, Enbridge Gas confirms that the SFVD rate design alternative is aligned with the fully fixed rate design approach that the OEB approved for Ontario electric utilities and that electric utilities have since implemented for their customers.

Enbridge Gas notes that the OEB has not made any change to Ontario electric utilities' equity thickness, which has remained at 40%, or to Return on Equity (ROE), in light of fully fixed rate design for distribution service.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 2, Page 24, Paragraph 59

Preamble:

"To better understand the potential future electricity demand and capacity needs, the IESO is undertaking a Pathways to Decarbonization study and demand scenario. This study will be used to explore the implications of operating Ontario's electricity system under significantly higher demand with a non-emitting supply mix. It is anticipated that the report will be available in November of 2022."

Question(s):

Please file a copy of the *Pathways to Decarbonization Study* report to the Minister of Energy, dated December 15, 2022, so that it is on the record in this proceeding.

Response:

The Pathways to Decarbonization Study is publicly available on the IESO's website[1].

[1]Pathways to Decarbonization, December 15, 2022, https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization.