ENBRIDGE

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Enbridge Gas Inc.
P. O. Box 2001
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Chatham, ON N7M 5M1

June 17, 2022

VIA RESS AND EMAIL

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-2022-0110
2021 Utility Earnings and Disposition of Deferral & Variance Account Balances Application and Evidence

Further to the submission filed on May 31, 2022, enclosed please find the following updated exhibits:

Exhibit	**Correction**
B-3-1, Page 2 and 6	The 2021 Actual balance for Corporate Shared Services and Compensation and Benefits were misstated, resulting in an incorrect $ and % change for those categories. There was no impact on Total Utility O&M. An updated Table 1 and Appendix A has been provided.

In the event that you have any questions on the above or would like to discuss in more detail, please do not hesitate to contact me.

Sincerely,

(Original Digitally Signed)

Richard Wathy
Technical Manager, Regulatory Applications

cc.: D. Stevens (Aird & Berlis)

EXHIBIT LIST

A – Overview and Introduction

Exhibit	Tab	Schedule	Contents
A	1		Exhibit List
	2		Application
	3		Overview and Approvals Required

B- Utility Results and Earning Sharing

Exhibit	Tab	Schedule	Contents
B	1		2021 Earnings Sharing Amount and Determination Process
		1	Return on Rate Base & Equity and Earning Sharing Determination
		2	Utility Income
		3	Utility Income Tax
		4	Utility Rate Base and Continuity Schedules
		5	Capital Structure and Cost of Capital
		6	Reconciliation of Audited Income to Corporate
	2	1	Delivery Revenue by Service Type and Rate Class
		2	Total Customers and Revenue by Service Type and Rate Class

B- Utility Results and Earning Sharing

C- Enbridge Gas Inc 2021 Deferral and Variance Accounts

D - EGD Rate Zone Deferral and Variance Accounts

E – Union Rate Zones Deferral and Variance Accounts

E – Union Rate Zones Deferral and Variance Accounts

F – Rate Allocation

/u

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule. B);

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an order or orders clearing certain commodity and non-commodity related deferral or variance accounts.

APPLICATION

1. Enbridge Gas Distribution Inc. (referred to in the evidence as EGD, Enbridge or the Company) and Union Gas Limited (referred to in the evidence as Union or the Company) (together the Utilities) were Ontario corporations incorporated under the laws of the Province of Ontario carrying on the business of selling, distributing, transmitting and storing natural gas within the meaning assigned in the *Ontario Energy Board Act*, 1998 (the Act). In the August 30, 2018 EB-2017-0306/0307 Decision and Order (the MAADs Decision), the Ontario Energy Board (OEB) approved the amalgamation of the Utilities, as well as a five-year deferred rebasing term during which a price cap rate-setting model would apply.

2. Effective January 1, 2019 the Utilities amalgamated to become Enbridge Gas Inc. (Enbridge Gas). Following amalgamation, Enbridge Gas has maintained the existing rates zones of EGD and Union (the EGD, Union North West, Union North East and Union South rate zones).[1] Enbridge Gas has also maintained most of the existing deferral and variance accounts for each Rate Zone.

[1] Collectively the Union North West, Union North East and Union South rates zones are referred to as "Union rate zones". Union North West and Union North East are collectively referred to as "Union North".

3. Enbridge Gas, the Applicant, hereby applies to the OEB, pursuant to Section 36 of the *Ontario Energy Board Act*, 1998, for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

Earnings Sharing

4. In the MAADs Decision, the OEB approved, among other things, an asymmetrical earnings sharing mechanism (ESM) during the deferred rebasing period, where each year any earnings in excess of 150 basis points over the OEB-approved return on equity (ROE) would be shared 50/50 between the Utilities and ratepayers.

5. In 2021, Enbridge Gas's actual utility earnings did not exceed the OEB-approved ROE by more than 150 basis points. Accordingly, no ESM amount is proposed to be shared with ratepayers.

Enbridge Gas Inc.

6. The OEB has approved several deferral and variance accounts that relate to Enbridge Gas as a whole (and not to specific Rate Zone(s)). These accounts are listed at Exhibit C, Tab 1, Schedule 1.

7. Enbridge Gas proposes to clear the 2021 balance in the Tax Variance Deferral Account (TVDA). Enbridge Gas is not seeking approval to clear any part of the balance in the Accounting Policy Changes Deferral Account (APCDA), in the Covid-19 Emergency Incremental Cost Deferral Account (COVEICDA) and in the Incremental Capital Module Deferral Account (ICMDA). Details on these accounts are presented in this application for information purposes. The balances in these accounts will be brought forward for clearance in a future application.

EGD Rate Zone

8. As approved in the MAADs Decision and the 2019 Rates Case (EB-2018-0305), Enbridge Gas has maintained substantially the same deferral and variance accounts for the EGD rate zone as during its 2014-2018 Custom IR term.

9. Enbridge Gas seeks approval to clear the final balances of certain EGD rate zone deferral and variance accounts for 2021 as set out at Exhibit C, Tab 1, Schedule 1.

Union Rate Zones

10. As approved in the MAADs Decision and the 2019 Rates Case (EB-2018-0305), Enbridge Gas has maintained substantially the same deferral and variance accounts for the Union Rate Zones as during its 2014-2018 IR term.

11. Enbridge Gas seeks approval to clear the final balances of certain Union rate zones deferral and variance accounts for 2021 as set out at Exhibit C, Tab 1, Schedule 1.

Relief Requested

12. Enbridge Gas therefore applies to the OEB for such final, interim or other orders as may be necessary or appropriate for the clearance or disposition of the 2021 deferral and variance accounts requested in Exhibit C, Tab 1, Schedule 1. The proposed manner of disposition is described at Exhibit F. Enbridge Gas proposes to clear the balances in these accounts with the first available QRAM application following the OEB's approval, as early as January 1, 2023.

13. Enbridge Gas requests that certain information included at Exhibit D, Tab 1, Schedule 6 be treated as confidential under the OEB's Practice Direction on Confidential Filings. Equivalent information has been treated as confidential in prior deferral and variance account clearance proceedings.

14. Enbridge Gas requests that this proceeding be heard in writing.

15. Enbridge Gas further applies to the OEB pursuant to the provisions in the Act and the OEB's *Rules of Practice and Procedure* for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

16. This Application is supported by written evidence. This evidence may be amended from time to time as required by the OEB, or as circumstances may require.

17. The persons affected by this application are the customers resident or located in the municipalities, police villages and First Nations reserves served by Enbridge Gas, together with those to whom Enbridge Gas sells gas, or on whose behalf Enbridge Gas distributes, transmits or stores gas. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.

18. Enbridge Gas requests that a copy of every document filed with the OEB in this proceeding be served on the Applicant and Applicant's counsel, as follows:

The Applicant:

Mr. Richard Wathy
Technical Manager, Regulatory Applications
Enbridge Gas Inc.

Address for personal service	Enbridge Gas Inc. P. O. Box 2001 50 Keil Drive North Chatham, ON N7M 5M1
Telephone:	519-365-5376
Fax:	(519) 436-4641
Email:	Richard.Wathy@enbridge.com EGIRegulatoryproceedings@enbridge.com

- and –

The Applicant's counsel:

Mr. David Stevens
Aird & Berlis LLP

Address for personal service and mailing address:	Brookfield Place, P.O. Box 754 Suite 1800, 181 Bay Street Toronto, Ontario M5J 2T9
Telephone:	416-863-1500
Fax:	416-863-1515
Email:	dstevens@airdberlis.com

DATED: May 31, 2022, at Chatham, Ontario

ENBRIDGE GAS INC.

[Original digitally signed by]

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Richard Wathy
Technical Manager, Regulatory Applications

2021 DEFERRAL ACCOUNT DISPOSITION AND EARNINGS SHARING OVERVIEW AND APPROVALS REQUESTED

1. Enbridge Gas Inc. (Enbridge Gas) is applying to the Ontario Energy Board (OEB) pursuant to section 36 of the *OEB Act* for approval to dispose and recover certain 2021 deferral and variance account final balances for Enbridge Gas, and the Enbridge Gas Distribution (EGD) and Union Gas (Union)[1] rate zones. Enbridge Gas is also presenting the 2021 earnings sharing mechanism (ESM) calculations for the amalgamated utility.

2. The evidence in this Application is organized as follows:
   Exhibit A: Overview and Introduction
   Exhibit B: 2021 Utility Results and Earnings Sharing Amount
   Exhibit C: Enbridge Gas Inc. 2021 Deferral and Variance Accounts
   Exhibit D: EGD Rate Zone Deferral and Variance Accounts
   Exhibit E: Union Rate Zones Deferral and Variance Accounts
   Exhibit F: Rate Allocation
   Exhibit G: OEB Scorecard
   Exhibit H: IRP Annual Report (to be filed at a later date)

3. Enbridge Gas proposes that the impacts which result from the disposition of 2021 deferral and variance account balances be implemented with the first available QRAM application following the OEB's approval, as early as January 1, 2023, to align with other rate changes implemented through the Quarterly Rate Adjustment Mechanism (QRAM).

[1] "Union rate zones" collectively refers to Union North West, Union North East and Union South.

1. Relief requested

4. Enbridge Gas seeks approval to clear the final balances of certain Enbridge Gas, EGD rate zone, and Union rate zones 2021 deferral and variance accounts. The balances of the 2021 deferral and variance accounts are set out at Exhibit C, Tab 1, Schedule 1. For ease of reference, a copy of Exhibit C, Tab 1, Schedule 1 is attached at Appendix A to this exhibit.

5. Explanations for the balances in each account are set out at Exhibit C (Enbridge Gas Inc.), Exhibit D (EGD rate zone) and Exhibit E (Union rate zones). The evidence also indicates which accounts Enbridge Gas does not seek to clear in this proceeding. The proposed clearance methodology for the accounts being cleared is set out at Exhibit F.

6. In the MAADs Decision (EB-2017-0306/0307), the OEB approved, among other things, an asymmetrical earnings sharing mechanism (ESM) during the 2019-2023 deferred rebasing period, where each year any earnings in excess of 150 basis points over the OEB-approved return on equity (ROE) would be shared 50/50 between Enbridge Gas and ratepayers.

7. Enbridge Gas's actual 2021 utility earnings did not exceed the OEB-approved ROE by more than 150 basis points. Accordingly, no ESM amount is proposed to be shared with ratepayers.

2. Disposition of deferral and variance accounts

8. Integration of the legacy billing systems for EGD and Union Gas enables Enbridge Gas to dispose of balances in the 2021 deferral and variance accounts as a one-time adjustment for all customers. Enbridge Gas proposes to dispose of the 2021 deferral

and variance accounts as a one-time adjustment for all general service, in-franchise contract and ex-franchise rate classes.

9. The proposed approach to the one-time adjustment is consistent between the EGD and Union rate zones and, subject to OEB approval as to timing, will be disposed of as part of the January 2023 bills that customers receive in Febraury 2023.

3. Parkway west project costs account interim disposition

10. Enbridge Gas is seeking interim disposition of the 2021 balance in the Parkway West Project Costs Deferral Account (179-136), consistent with the 2016 to 2020 deferral and variance account disposition proceedings. In the 2016 deferral account proceeding, the OEB noted that “all parties agreed that the 2016 balance in the Parkway West Project Costs Account should be disposed of only on an interim basis to allow the OEB to perform a prudence review of the capital overspend prior to final disposition of the balance in the account.”[2] Consistent with this direction, Enbridge Gas will seek approval of the final disposition of this account as part of a subsequent proceeding when all the project costs have been incurred and the prudence of the project costs are assessed.

[2] EB-2017-0091 Updated Settlement Agreement Proposal, page 12.

ENBRIDGE GAS
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym		Col. 1 Principal ($000's)	Col. 2 Interest ($000's)	Col. 3 Total ($000's)	Col.4 Reference
				Forecast for clearance at January 1, 2023			
	EGD Rate Zone Commodity Related Accounts						
1.	Storage and Transportation D/A	2021 S&TDA		7,942.5	97.0	8,039.5	D-1, Page 2
2.	Transactional Services D/A	2021 TSDA		(3,904.1)	(35.4)	(3,939.6)	D-1, Page 4
3.	Unaccounted for Gas V/A	2021 UAFVA		753.9	4.5	758.4	D-1, Page 6
4.	Total commodity related accounts			4,792.2	66.2	4,858.4	
	EGD Rate Zone Non Commodity Related Accounts						
5.	Average Use True-Up V/A	2021 AUTUVA		14,934.3	135.5	15,069.8	D-1, Page 10
6.	Gas Distribution Access Rule Impact D/A	2021 GDARIDA		-	-	-	D-1, Page 23
7.	Deferred Rebate Account	2021 DRA		4,359.4	53.5	4,412.9	D-1, Page 12
8.	Transition Impact of Accounting Changes D/A	2021 TIACDA		4,435.8	-	4,435.8	D-1, Page 1
9.	Electric Program Earnings Sharing D/A	2021 EPESDA		-	-	-	D-1, Page 23
10.	Open Bill Revenue V/A	2021 OBRVA		-	-	-	D-1, Page 23
11.	Ex-Franchise Third Party Billing Services V/A	2021 EXFTPBSVA		-	-	-	D-1, Page 23
12.	RNG Injection Service V/A	2021 RNGISVA		-	-	-	D-1, Page 23
13.	OEB Cost Assessment V/A	2021 OEBCAVA		2,550.3	31.5	2,581.8	D-1, Page 13
14.	Dawn Access Costs D/A	2021 DACDA		1,968.0	17.9	1,985.9	D-1, Page 16
15.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Di	2021 P&OPEBFAVACPDVA		-	-	-	D-1, Page 23
16.	**Total EGD Rate Zone (for clearance)**			**33,040.0**	**304.5**	**33,344.6**	
	Union Rate Zones Gas Supply Accounts	OEB Account Number					
17.	Upstream Transportation Optimization	179-131	2021	8,616.3	78.2	8,694.5	E-1, Page 6
18.	Spot Gas Variance Account	179-107	2021	-	-	-	E-1, Page 58
19.	Unabsorbed Demand Costs Variance Account	179-108	2021	(1,665.6)	(28.3)	(1,693.9)	E-1, Page 1
20.	Base Service North T-Service TransCanada Capacity	179-153	2021	83.5	0.9	84.4	E-1, Page 52
21.	Total Gas Supply Accounts			7,034.2	50.8	7,085.0	
	Union Rate Zones Storage Accounts						
22.	Short-Term Storage and Other Balancing Services	179-70	2021	3,576.9	32.5	3,609.4	E-1, Page 8
	Union Rate Zones Other Accounts						
23.	Normalized Average Consumption	179-133	2021	18,997.4	239.4	19,236.8	E-1, Page 13
24.	Deferral Clearing Variance Account	179-132	2021	(3,120.4)	(45.3)	(3,165.7)	E-1, Page 21
25.	OEB Cost Assessment Variance Account	179-151	2021	907.1	11.4	918.5	E-1, Page 49
26.	Unbundled Services Unauthorized Storage Overrun	179-103	2021	-	-	-	E-1, Page 58
27.	Gas Distribution Access Rule Costs	179-112	2021	-	-	-	E-1, Page 58
28.	Conservation Demand Management	179-123	2021	-	-	-	E-1, Page 58
29.	Parkway West Project Costs	179-136	2021	(603.3)	(6.4)	(609.7)	E-1, Page 25
30.	Brantford-Kirkwall/Parkway D Project Costs	179-137	2021	(45.0)	(0.4)	(45.4)	E-1, Page 29
31.	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	2021	24.0	0.4	24.4	E-1, Page 41
32.	Lobo D/Bright C/Dawn H Compressor Project Costs	179-144	2021	(112.1)	(3.6)	(115.7)	E-1, Page 44
33.	Burlington-Oakville Project Costs	179-149	2021	(51.0)	(0.5)	(51.5)	E-1, Page 47
34.	Panhandle Reinforcement Project Costs	179-156	2021	(3,162.0)	(35.9)	(3,197.9)	E-1, Page 53
35.	Sudbury Replacement Project	179-162	2021	-	-	-	E-1, Page 58
36.	Parkway Obligation Rate Variance	179-138	2021	-	-	-	E-1, Page 58
37.	Unauthorized Overrun Non-Compliance Account	179-143	2021	-	-	-	E-1, Page 58
38.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Di	179-157	2021	-	(1,345.6)	(1,345.6)	E-1, Page 56
39.	Unaccounted for Gas Volume Variance Account	179-135	2021	20,501.3	176.9	20,678.2	E-1, Page 31
40.	Unaccounted for Gas Price Variance Account	179-141	2021	3,358.3	31.8	3,390.1	E-1, Page 38
41.	Total Other Accounts			36,694.3	(977.8)	35,716.5	
42.	**Total Union Rate Zones (for clearance)**			**47,305.4**	**(894.6)**	**46,410.8**	
	EGI Accounts						
43.	Earnings Sharing D/A	179-382	2021	-	-	-	C-1, Page 1
44.	Tax Variance - Accelerated CCA - EGI	179-383	2021	(19,162.6)	(227.2)	(19,389.8)	C-1, Page 12
45.	IRP Operating Costs Deferral Account	179-385	2021	57.7	0.5	58.2	C-1, Page 15
46.	IRP Capital Costs Deferral Account	179-386	2021	-	-	-	C-1, Page 1
47.	Expansion of Natural Gas Distribution Systems V/A	179-380	2021	-	-	-	C-1, Page 1
48.	**Total EGI Accounts (for clearance)**			**(19,104.9)**	**(226.7)**	**(19,331.6)**	
49.	**Total Deferral and Variance Accounts (for clearance)**			**61,240.5**	**(816.7)**	**60,423.8**	
	Not Being Requested for Clearance						
50.	Accounting Policy Changes D/A - Pension - EGI	179-120	2021	169,431.8	-	169,431.8	C-1, Page 2
51.	Accounting Policy Changes D/A - Other - EGI	179-120	2019	(1,749.5)	(52.8)	(1,802.3)	C-1, Page 2
52.	Accounting Policy Changes D/A - Other - EGI	179-120	2020	(14,789.5)	(249.4)	(15,038.9)	C-1, Page 2
53.	Accounting Policy Changes D/A - Other - EGI	179-120	2021	(13,864.6)	(168.8)	(14,033.4)	C-1, Page 2
54.	Tax Variance - Integration Capital Additions - EGI	179-383	2020	(3,736.3)	(28.6)	(3,764.8)	C-1, Page 12
55.	Tax Variance - Integration Capital Additions - EGI	179-383	2021	(10,462.6)	(80.0)	(10,542.7)	C-1, Page 12
56.	Incremental Capital Module Deferral Account - EGD	2020 ICMDA	2020	(254.0)	(3.2)	(257.2)	C-1, Page 1
57.	Incremental Capital Module Deferral Account - EGD	2021 ICMDA	2021	175.5	2.0	177.5	C-1, Page 1
58.	Incremental Capital Module Deferral Account - UGL	179-159	2019	(6,869.6)	(196.1)	(7,065.7)	C-1, Page 1
59.	Incremental Capital Module Deferral Account - UGL	179-159	2020	(5,615.4)	(91.9)	(5,707.2)	C-1, Page 1
60.	Incremental Capital Module Deferral Account - UGL	179-159	2021	(14,353.4)	(147.2)	(14,500.6)	C-1, Page 1
61.	Impacts Arising from the COVID-19 Emergency D/A - EGI	2020 IACEDA	2020	1,377.5	20.3	1,397.8	C-1, Page 1
62.	Impacts Arising from the COVID-19 Emergency D/A - EGI	2021 IACEDA	2021	34.3	0.4	34.7	C-1, Page 1
63.	**Total of Accounts not being requested for clearance**			**99,324.2**	**(995.3)**	**98,328.9**	

2021 ENBRIDGE GAS INC. EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. For the year ended December 31, 2021, Enbridge Gas Inc. (Enbridge Gas, or the Company) is not in an earnings sharing position, as its achieved return on rate base and return on equity are below the threshold required for sharing. The earnings sharing calculation is shown at Exhibit B, Tab 1, Schedule 1, while supporting schedules that show the calculation of utility rate base, utility income and taxes, and the utility capital structure components, are contained in the balance of the B Exhibits. Exhibit B, Tab 1, Schedule 6 sets out a reconciliation of audited income to corporate income.

2. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2017-0306/0307 OEB Decision and Order, dated August 30, 2018, at pages 28 and 29, and within the EB-2017-0306 pre-filed evidence at Exhibit B, Tab 1, at pages 42 and 43:
    - if in any calendar year during the deferred rebasing term, Enbridge Gas's actual utility ROE is more than 150 basis points above the OEB-approved ROE for that year (updated annually by the OEB), then the resultant amount shall be shared equally (i.e., 50/50) between Enbridge Gas and its ratepayers;
    - for the purposes of the ESM, Enbridge Gas shall calculate its earnings using generally accepted accounting principles (GAAP) consistent with its external reporting, including the regulatory rules prescribed by the OEB from time to time;
    - all revenues and costs that would otherwise be included in a cost of service application shall be included in the earnings sharing calculation.

3. While the threshold or benchmark for Enbridge Gas's earnings sharing has changed from that of each legacy utility[1], the general process followed for calculating earnings sharing amounts is consistent with each utilities prior incentive regulation terms.

4. As articulated above, within Exhibit B, Tab 1, Schedule 1, the Company has calculated earnings for sharing in two ways for confirmation purposes.

5. In part A), a return on rate base method is shown, while in part B), a return on equity from a deemed equity embedded within rate base perspective is shown. Column 2 within the exhibit provides references indicating where additional evidence in support of the determination of the amounts in the calculation can be found. Column 3 contains results shown in millions of dollars, or percentages.

<u>1. Part A)</u>

6. The level of utility income, \$846.5 million (Line 4) divided by the level of utility rate base, \$14,216.1 million (Line 5) generates a utility return on rate base of 5.954% (Line 6).

7. When compared to the Company's required rate of return for ESM determination, of 6.167% (Line 7), as determined within the capital structure required in support of the determined rate base amount (inclusive of the 150 basis point deadband on ROE before earnings sharing is triggered), there is a resulting deficiency of 0.213% (Line 8) on total rate base.

8. As shown in Lines 9 through 11, the deficiency of 0.213% multiplied by the rate base of \$14,216.1 million, produces a net under earnings or deficiency of \$30.3 million, which from a pre-tax perspective (\$30.3 million divided by the reciprocal, 73.5%, of

[1] Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union).

the corporate tax rate which is 26.5%), results in a $41.2 million gross amount of under earnings, and therefore nothing to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

<u>2. Part B) (Confirming the Calculated Earnings Sharing)</u>

9. Net utility income applicable to common equity is first determined.

10. The $889.6 million (Line 14) of utility income before income tax, less utility taxes of $43.1 million (Line 19), produces the $846.5 million of utility income used in part A) above (at Line 4).

11. In order to determine utility net income applicable to a deemed common equity percentage within rate base, all long term debt, short term debt and preference share costs must also be reduced against the part A) $846.5 million utility income.

12. These reductions are shown at Lines 15, 16 and 17 which, along with the utility income tax reduction already mentioned and shown at Line 19, results in a net income applicable to common equity of $473.3 million, shown at Line 20.

13. The $473.3 million, divided by the deemed common equity level of $5,117.8 million (Line 21, calculated as 36% of the $14,216.1 million rate base) produces a return on equity of 9.249% (Line 23). When comparing the 9.249% achieved return on equity to the threshold ROE percentage of 9.840% (Line 22), which is the OEB-approved formula return on equity for 2021 of 8.340% plus the 150 basis point deadband before sharing, there is a deficiency in ROE of 0.591% (Line 24).

14. The 0.591% multiplied by the common equity level of $5,117.8 million (Line 21) produces a net under earnings or deficiency of $30.3 million, which from a pre-tax perspective ($30.3 million divided by the reciprocal, 73.5%, of the corporate tax

rate), results in a $41.2 million gross amount of under earnings, and therefore nothing to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

3. Process Description

15. The calculation of utility earnings and any earnings sharing requirement starts with financial results contained within the Enbridge Gas corporate trial balance. The Company notes that corporate trial balance includes the elimination of transactions between each of the rate zones. This predominantly relates to the elimination of regulated and unregulated storage and transmission revenues that would have been reflected in the Union rate zones, offset by a corresponding elimination of gas costs that would have been reflected for the EGD rate zone. This reflects the fact that from a corporate perspective, EGD rate zone delivery revenues are contributing to the costs of Union rate zones regulated and unregulated storage and transmission services.

16. From there, in order to calculate the utility rate base, income, and capital structure results, and supporting evidence exhibits, various adjustments, regroupings or eliminations are required. This is accomplished by following and applying regulatory rules as prescribed by the OEB and the standards associated with cost of service rate related accounting processes. Examples are:
    - determination of rate base amounts using the average of monthly averages value concept,
    - elimination of corporate interest expense due to the treatment of interest expense as embedded in the capital structure balanced to rate base; and,
    - elimination of corporate income taxes due to the determination of income taxes specific to utility results.

17. In addition, Enbridge Gas has made the appropriate adjustments in relation to non-standard legacy EGD and Union rate regulated items which the OEB has either decided in the past or are required in order to determine an appropriate utility return on equity. Examples are:
    - rate base disallowance from EBRO 473 and 479 Decisions (Mississauga Southern Link project amounts),
    - exclusion of non-utility or unregulated activities; and,
    - elimination of approved shareholder incentives (such as Demand Side Management incentives, amounts related to Transactional Services, short-term storage, and net optimization incentives, and amounts related to Open Bill program incentives).

SUMMARY
RETURN ON RATE BASE & EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS INC.

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2021

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
			($Millions) & (%'s)
2.	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	889.6
3.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	43.1
4.	**Utility Income**		**846.5**
5.	**Utility Rate Base**	(Ex. B, Tab 1, Sch. 4)	**14,216.1**
6.	Indicated Return on Rate Base %	(line 4 / line 5)	5.955%
7.	Less: Required Rate of Return %	(Ex. B, Tab 1, Sch. 5)	6.167%
8.	**(Deficiency) / Sufficiency %**		**-0.213%**
9.	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(30.2)
10.	Provision for Income Taxes		(10.9)
11.	**Gross Earnings (Deficiency) / Sufficiency**	(line 9 / 73.5%)	**(41.1)**
12.	**50% Earnings sharing to ratepayers**	(if line 11 > 1, line 11 x 50%)	-
13.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
14.	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	889.6
15.	Less: Long Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	371.3
16.	Less: Short Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	1.9
17.	Less: Cost of Preferred Capital	(Ex. B, Tab 1, Sch. 5)	0.0
18.	Net Income before Income Taxes		516.5
19.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	43.1
20.	**Net Income Applicable to Common Equity**	(line 18 - line 19)	**473.4**
21.	Common Equity	(Ex. B, Tab 1, Sch. 5)	5,117.8
22.	Approved ROE (including deadband before earning sharing) %	(Board-approved + 150bp)	9.840%
23.	Achieved Rate of Return on Equity %	(line 20 / line 21)	9.249%
24.	**Resulting (Deficiency) / Sufficiency in Return on Equity %**		**-0.591%**
25.	Net Earnings (Deficiency) / Sufficiency	(line 21 x line 24)	(30.2)
26.	Provision for Income Taxes		(10.9)
27.	**Gross Earnings (Deficiency) / Sufficiency**	**(line 25 / 73.5%)**	**(41.1)**
28.	**50% Earnings sharing to ratepayers**	(if line 27 > 1, line 27 x 50%)	-

EGI UTILITY INCOME
2021 ACTUAL

Line No.		Reference	Col. 1 Corporate (a)	Col. 2 Unregulated Storage (b)	Col. 3 Adjustments (c)		Col. 4 Utility Income (d) = (a)-(b)+(c)
							($Millions)
1.	Gas sales and distribution	(Ex. B, Tab 2, Sch. 2)	4,513.2	-	(32.6)	(i)	4,480.6
2.	Transportation	(Ex. B, Tab 2, Sch. 3)	143.0	0.4	(0.8)	(ii)	142.0
3.	Storage	(Ex. B, Tab 2, Sch. 3)	159.7	153.6	(0.1)	(iii)	6.0
4.	Other operating revenue	(Ex. B, Tab 2, Sch. 4)	64.3	1.8	(13.4)	(iv)	49.1
5.	Other income	(Ex. B, Tab 2, Sch. 4)	7.2	-	(6.3)	(viii)	0.9
6.	Total operating revenue		4,887.4	155.8	(53.1)		4,678.5
7.	Gas costs		2,146.2	20.2	(15.4)	(i)	2,110.6
8.	Operation and maintenance	(Ex. B, Tab 3, Sch. 1)	938.6	18.5	(4.0)	(v)	916.2
9.	Depreciation and amortization expense		676.8	14.9	(22.6)	(vi)	639.3
10.	Fixed financing costs		6.3	-	0.5	(vii)	6.8
11.	Municipal and other taxes		117.9	1.8	-		116.1
12.	Cost of service		3,885.8	55.4	(41.5)		3,788.9
13.	Utility income before income taxes						889.6
14.	Income tax expense	(Ex. B, Tab 1, Sch. 3)					43.1
15.	Utility income						846.5

Notes on Adjustments:

(i)	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(15.4)
	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(17.2)
		(32.6)
(ii)	Elimination of the Union rate zone shareholder portion of net optimization activity (before tax)	(0.8)
(iii)	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax)	(0.1)
(iv)	Adjust EGD rate zone OBA costs to reflect EB-2013-0099 approved unit costs agreed to be used for determining net revenue	(4.3)
	Elimination of EGD rate zone Open Bill shareholder incentive	0.3
	Elimination of EGD rate zone shareholder portion of transactional service revenues	(1.8)
	Elimination of demand-side management incentive	(6.9)
	Elimination of EGD rate zone net revenue from ABC T-service, considered to be non-utility	(0.8)
		(13.4)
(v)	Elimination of donations	(3.6)
	Elimination of EB-2021-0204 Assurance of Voluntary Compliance amount	(0.1)
	Elimination of non-utility costs and expenses relating to support of the EGD rate zone ABC T-service program	(0.3)
		(4.0)
(vi)	Eliminate amortization of PPD (purchase price discrepancy)	(22.5)
	Eliminate depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479)	(0.1)
		(22.6)
(vii)	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	0.5
(viii)	Elimination of interest income from investments not included in utility rate base	(0.1)
	Elimination of interest income from affiliates	(1.6)
	Elimination of the revenue indemnification received from Enbridge Inc. related to a non-utility Corporate tax planning Part VI.1 tax transfer to EGI	(4.6)
		(6.3)

CALCULATION OF EGI UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2021 ACTUAL

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	889.6	889.6	
	Add			
2.	Depreciation and amortization	639.3	639.3	
3.	Accrual based pension and OPEB costs	37.6	37.6	
4.	Other non-deductible items	0.3	0.3	
5.	Total Add Back	677.2	677.2	
6.	Sub-total	1,566.9	1,566.9	
	Deduct			
7.	Capital cost allowance	829.4	829.4	
8.	Items capitalized for regulatory purposes	152.9	152.9	
9.	Amortization of share/debenture issue expense	0.4	0.4	
10.	Amortization of C.D.E. and C.O.G.P.E	-	-	
11.	Other	6.3	6.3	
12.	Cash based pension and OPEB costs	42.1	42.1	
13.	Total Deduction	1,031.1	1,031.1	
14.	Taxable income	535.8	535.8	
15.	Income tax rates	15.00%	11.50%	
16.	Tax provision excluding interest shield	80.4	61.6	142.0
	Tax shield on interest expense			
17.	Rate base	14,216.1		
18.	Return component of debt	2.62%		
19.	Interest expense	373.1		
20.	Combined tax rate	26.50%		
21.	Income tax credit			(98.9)
22.	Total utility income taxes			43.1

EGI UTILITY RATE BASE
2021 ACTUAL

Line No.		Col. 1 2021 Actual	Col. 2 2020 Actual
		($Millions)	($Millions)
	Property, Plant, and Equipment		
1.	Gross property, plant, and equipment	21,522.4	20,582.1
2.	Accumulated depreciation	(7,994.0)	(7,571.2)
3.	Net property, plant, and equipment	13,528.4	13,010.8
	Allowance for Working Capital		
4.	Materials and supplies	92.5	82.2
5.	ABC receivable	(15.5)	(22.3)
6.	Customer security deposits	(68.9)	(81.8)
7.	Prepaid expenses	4.7	3.1
8.	Balancing gas	59.5	59.5
9.	Gas in storage	594.7	487.5
10.	Working cash allowance	20.9	23.0
11.	Total Working Capital	687.7	551.2
12.	Utility Rate Base	14,216.1	13,562.0

EGI UTILITY PROPERTY, PLANT, AND EQUIPMENT
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2021 ACTUAL

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
	EGD Rate Zone			
1.	Underground storage plant	485.6	(148.5)	337.1
2.	Distribution plant	9,640.8	(3,070.8)	6,570.0
3.	General plant	660.6	(493.6)	167.0
4.	Plant held for future use	1.7	(1.4)	0.2
5.	EGD Rate Zone Total	10,788.6	(3,714.3)	7,074.3
	Union Rate Zones			
6.	Intangible plant	1.7	(1.3)	0.4
7.	Local storage plant	32.0	(17.8)	14.2
8.	Underground storage plant	831.3	(335.4)	495.9
9.	Transmission plant	3,767.4	(1,188.6)	2,578.8
10.	Distribution plant - Southern operations	3,529.2	(1,515.5)	2,013.7
11.	Distribution plant - Northern and Eastern operations	2,134.6	(980.1)	1,154.5
12.	General plant	437.6	(241.0)	196.7
13.	Union Rate Zones Total	10,733.8	(4,279.7)	6,454.1
14.	EGI Total	21,522.4	(7,994.0)	13,528.4

EGI UTILITY GROSS PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2021 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2020	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2021	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2021	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	EGD Rate Zone Underground Storage Plant							
1.	Land and gas storage rights (450/451)	47.6	1.3	-	48.9	(1.0)	47.9	46.6
2.	Structures and improvements (452)	31.5	0.6	-	32.1	(0.1)	32.0	31.5
3.	Wells (453)	70.0	22.4	-	92.4	-	92.4	71.0
4.	Well equipment (454)	12.6	0.7	-	13.4	-	13.4	12.7
5.	Field Lines (455)	115.4	12.3	-	127.7	-	127.7	115.9
6.	Compressor equipment (456)	159.7	36.4	-	196.2	(0.5)	195.7	164.3
7.	Measuring and regulating equipment (457)	11.2	-	-	11.2	-	11.2	11.2
8.	Base pressure gas (458)	32.4	-	-	32.4	-	32.4	32.4
9.	Sub-Total	480.5	73.8	-	554.3	(1.5)	552.7	485.6
	EGD Rate Zone Distribution Plant							
10.	Renewable Natural Gas (461)	-	-	-	-	-	-	-
11.	Land (470)	53.7	0.5	-	54.2	-	54.2	54.0
12.	Offers to purchase (470)	-	-	-	-	-	-	-
13.	Land rights intangibles (471)	63.8	-	-	63.8	-	63.8	63.8
14.	Structures and improvements (472)	151.0	47.1	(4.7)	193.4	(0.3)	193.1	155.1
15.	Services, house reg & meter install. (473/474)	3,306.0	204.9	(9.9)	3,501.0	-	3,501.0	3,372.2
16.	Mains (475)	4,727.4	158.0	73.5	4,958.8	(2.2)	4,956.6	4,780.5
17.	NGV station compressors (476)	5.5	(0.3)	-	5.2	-	5.2	5.2
18.	Measuring and regulating equip. (477)	684.7	22.6	(8.8)	698.5	(0.5)	698.0	693.5
19.	Meters (478)	519.6	29.0	(21.3)	527.3	-	527.3	516.5
20.	Sub-Total	9,511.7	461.7	28.9	10,002.2	(3.1)	9,999.2	9,640.8
	EGD Rate Zone General Plant							
21.	Lease improvements (482)	0.1	(0.0)	-	0.1	(0.2)	(0.1)	(0.1)
22.	Office furniture and equipment (483)	21.0	(0.2)	-	20.7	-	20.7	20.5
23.	Transportation equipment (484)	61.7	5.1	(1.4)	65.4	(0.1)	65.4	59.4
24.	NGV conversion kits (484)	2.9	(0.0)	-	2.9	-	2.9	2.8
25.	Heavy work equipment (485)	20.2	2.9	-	23.1	-	23.1	20.3
26.	Tools and work equipment (486)	59.3	0.6	-	59.8	-	59.8	58.4
27.	Rental equipment (487)	1.8	(0.0)	-	1.8	-	1.8	1.8
28.	NGV rental compressors (487)	20.2	(12.4)	-	7.8	-	7.8	19.2
29.	NGV cylinders (484 and 487)	1.0	(0.4)	-	0.6	-	0.6	0.6
30.	Communication structures & equip. (488)	3.7	(0.1)	(1.8)	1.8	-	1.8	2.6
31.	Computer equipment (490)	32.1	2.3	(7.2)	27.1	-	27.1	30.3
32.	Software Aquired/Developed (491)	254.3	3.5	(23.5)	234.2	-	234.2	243.4
33.	CIS (491)	127.1	10.9	(124.1)	13.8	-	13.8	111.2
34.	WAMS (489)	92.1	(2.2)	-	89.9	-	89.9	90.0
35.	Sub-Total	697.4	9.8	(158.0)	549.2	(0.3)	548.9	660.6

	EGD Rate Zone Plant held for future use							
36.	Inactive services (102)	1.7	-	-	1.7	-	1.7	1.7
37.	EGD Rate Zone Total	10,691.2	545.3	(129.1)	11,107.3	(4.8)	11,102.5	10,788.6
	Union Rate Zones Intangible Plant							
38.	Franchises and consents (401)	1.2	-	-	1.2	-	1.2	1.2
39.	Other intangible plant (402)	0.5	-	-	0.5	-	0.5	0.5
40.	Sub-Total	1.7	-	-	1.7	-	1.7	1.7
	Union Rate Zones Local Storage Plant							
41.	Land (440)	0.0	-	-	0.0	-	0.0	0.0
42.	Structures and improvements (442)	5.2	0.7	-	5.9	-	5.9	5.2
43.	Gas holders - storage (443)	4.6	0.8	-	5.4	-	5.4	4.6
44.	Gas holders - equipment (443)	20.2	0.0	-	20.2	-	20.2	20.2
45.	Regulatory Overheads	1.8	0.3	-	2.1	-	2.1	1.9
46.	Sub-Total	31.8	1.8	-	33.6	-	33.6	32.0
	Union Rate Zones Underground Storage Plant							
47.	Land (450)	7.2	2.4	-	9.6	-	9.6	7.3
48.	Land rights (451)	32.0	-	-	32.0	-	32.0	32.0
49.	Structures and improvements (452)	69.3	0.9	-	70.2	-	70.2	69.4
50.	Wells (453)	48.0	1.1	-	49.1	-	49.1	48.5
51.	Field Lines (455)	50.6	0.5	-	51.1	-	51.1	50.8
52.	Compressor equipment (456)	470.1	2.9	-	473.0	-	473.0	470.6
53.	Measuring and regulating equipment (457)	86.4	(23.6)	-	62.8	-	62.8	85.5
54.	Base pressure gas (458)	36.2	-	-	36.2	-	36.2	36.2
55.	Regulatory Overheads	18.1	3.6	-	21.7	-	21.7	19.4
56.	Sub-Total	817.9	(12.1)	-	805.8	-	805.8	819.7
	Union Rate Zones Transmission Plant							
57.	Land (460)	82.2	2.5	-	84.7	-	84.7	82.6
58.	Land rights (461)	67.5	0.9	-	68.3	-	68.3	67.6
59.	Structures & improvements (462/463/464)	166.3	0.8	-	167.1	-	167.1	166.3
60.	Mains (465)	1,954.5	61.9	(4.1)	2,012.3	-	2,012.3	1,963.6
61.	Compressor equipment (466)	942.6	3.0	-	945.7	-	945.7	943.4
62.	Measuring & regulating equipment (467)	321.0	45.0	-	366.0	-	366.0	325.7
63.	Line Pack Gas	7.5	0.0	-	7.5	-	7.5	7.5
64.	Regulatory Overheads	200.1	31.4	-	231.5	-	231.5	210.7
65.	Sub-Total	3,741.6	145.5	(4.1)	3,883.1	-	3,883.1	3,767.4
	Union Rate Zones Distribution Plant - Southern Operations							
66.	Land (470)	12.6	4.1	-	16.7	-	16.7	15.3
67.	Land rights (471)	8.9	0.2	-	9.1	-	9.1	8.9
68.	Structures and improvements (472)	139.6	6.6	-	146.2	-	146.2	140.9
69.	Services - metallic (473)	128.4	2.4	(0.3)	130.5	-	130.5	129.2
70.	Services - plastic (473)	956.7	41.1	(1.8)	996.0	-	996.0	974.7
71.	Regulators (474)	97.1	13.4	(5.8)	104.8	-	104.8	102.6
72.	House regulators & meter installations (474)	76.9	10.3	-	87.2	-	87.2	78.1
73.	Mains - metallic (475)	581.8	103.5	(0.9)	684.3	-	684.3	598.0
74.	Mains - plastic (475)	706.4	44.4	(0.5)	750.3	-	750.3	721.0
75.	Measuring & regulating equipment (477)	60.3	13.1	-	73.4	-	73.4	61.4
76.	Meters (478)	373.3	21.4	(3.3)	391.4	-	391.4	380.8
77.	Regulatory Overheads	315.2	40.4	-	355.6	-	355.6	329.9
78.	Sub-total	3,457.2	300.8	(12.7)	3,745.4	-	3,745.4	3,540.8

	Union Rate Zones Distribution Plant - Northern & Eastern Operations							
79.	Land (470)	5.0	0.3	-	5.3	-	5.3	5.2
80.	Land rights (471)	10.6	0.3	-	10.9	-	10.9	10.7
81.	Structures and improvements (472)	68.6	2.9	-	71.4	-	71.4	69.1
82.	Services - metallic (473)	110.1	1.4	(0.2)	111.2	-	111.2	110.5
83.	Services - plastic (473)	489.6	17.0	(0.8)	505.8	-	505.8	495.6
84.	Regulators (474)	39.0	0.8	(2.1)	37.7	-	37.7	39.2
85.	House regulators & meter installations (474)	41.5	0.7	-	42.3	-	42.3	41.7
86.	Mains - metallic (475)	680.5	40.2	(0.8)	719.9	-	719.9	688.0
87.	Mains - plastic (475)	238.7	7.9	(0.2)	246.3	-	246.3	240.5
88.	Measuring & regulating equipment (477)	151.3	4.2	-	155.5	-	155.5	152.2
89.	Meters (478)	96.8	6.3	(0.9)	102.2	-	102.2	97.3
90.	Regulatory Overheads	173.1	32.5	-	205.6	-	205.6	184.5
91.	Sub-total	2,104.7	114.4	(5.0)	2,214.1	-	2,214.1	2,134.6
	Union Rate Zones General Plant							
92.	Land (480)	0.5	-	-	0.5	-	0.5	0.5
93.	Structures & improvements (482)	73.8	16.3	-	90.2	-	90.2	78.4
94.	Office furniture and equipment (483)	10.1	0.0	(0.9)	9.3	-	9.3	10.0
95.	Office equipment - computers (483)	129.2	53.0	(69.1)	113.1	-	113.1	140.1
96.	Transportation equipment (484)	64.6	6.4	(5.1)	65.9	-	65.9	64.7
97.	Heavy work equipment (485)	19.2	2.3	(0.5)	21.0	-	21.0	19.3
98.	Tools and work equipment (486)	39.2	2.2	(6.1)	35.3	-	35.3	38.8
99.	NGV fuel equipment (487)	3.2	1.3	-	4.5	-	4.5	3.3
100.	Communication equipment (488)	14.3	0.1	(4.9)	9.4	-	9.4	13.0
101.	Regulatory Overheads	64.3	15.8	(9.8)	70.3	-	70.3	69.4
102.	Sub-total	418.6	97.4	(96.5)	419.5	-	419.5	437.6
103.	Union Rate Zones Total	10,573.6	647.9	(118.3)	11,103.2	-	11,103.2	10,733.8
104.	EGI Total	21,264.7	1,193.2	(247.4)	22,210.5	(4.8)	22,205.7	21,522.4

EGI UTILITY PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2021 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2020	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2021	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2021	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	EGD Rate Zone Underground Storage Plant								
1.	Land and gas storage rights (451)	(26.6)	(0.5)	-	-	(27.1)	-	(27.1)	(26.8)
2.	Structures and improvements (452)	(2.3)	(0.6)	-	-	(2.9)	0.1	(2.8)	(2.5)
3.	Wells (453)	(14.3)	(1.2)	-	-	(15.5)	-	(15.5)	(14.8)
4.	Well equipment (454)	(7.8)	(0.8)	-	-	(8.6)	-	(8.6)	(8.1)
5.	Field Lines (455)	(32.2)	(1.8)	-	-	(34.0)	-	(34.0)	(33.1)
6.	Compressor equipment (456)	(53.2)	(4.5)	-	-	(57.7)	0.3	(57.4)	(55.0)
7.	Measuring and regulating equipment (457)	(7.9)	(0.3)	-	-	(8.3)	-	(8.3)	(8.1)
8.	Sub-Total	(144.2)	(9.7)	-	-	(154.0)	0.3	(153.6)	(148.5)
	EGD Rate Zone Distribution Plant								
9.	Renewable Natural Gas (461)	-	-	-	-	-	-	-	-
10.	Land rights intangibles (471)	(5.7)	(0.8)	-	-	(6.5)	-	(6.5)	(6.1)
11.	Structures and improvements (472)	(42.9)	(10.2)	4.7	-	(48.3)	0.3	(48.0)	(42.7)
12.	Services, house reg & meter install. (473/47	(1,104.3)	(76.4)	9.9	28.4	(1,142.4)	-	(1,142.4)	(1,126.2)
13.	Mains (475)	(1,295.9)	(109.4)	(73.5)	16.9	(1,461.9)	2.2	(1,459.7)	(1,322.2)
14.	NGV station compressors (476)	(3.3)	(0.3)	-	-	(3.6)	-	(3.6)	(3.4)
15.	Measuring and regulating equip. (477)	(252.4)	(15.1)	8.8	0.7	(257.9)	0.5	(257.4)	(254.4)
16.	Meters (478)	(303.2)	(41.0)	21.3	0.0	(323.0)	-	(323.0)	(315.7)
17.	Sub-Total	(3,007.7)	(253.1)	(28.9)	46.1	(3,243.6)	3.0	(3,240.5)	(3,070.8)
	EGD Rate Zone General Plant								
18.	Lease improvements (482)	(0.1)	0.0	-	-	(0.1)	0.2	0.1	0.1
19.	Office furniture and equipment (483)	(12.6)	(1.9)	-	-	(14.4)	-	(14.4)	(13.4)
20.	Transportation equipment (484)	(32.2)	(5.3)	1.4	(0.1)	(36.3)	0.1	(36.3)	(33.7)
21.	NGV conversion kits (484)	0.4	(0.3)	-	-	0.2	-	0.2	0.3
22.	Heavy work equipment (485)	(6.0)	(0.6)	-	-	(6.6)	-	(6.6)	(6.3)
23.	Tools and work equipment (486)	(22.3)	(1.9)	-	-	(24.1)	-	(24.1)	(23.0)
24.	Rental equipment (487)	(1.1)	0.0	-	-	(1.1)	-	(1.1)	(1.1)
25.	NGV rental compressors (487)	(2.7)	0.2	-	-	(2.4)	-	(2.4)	(3.3)
26.	NGV cylinders (484 and 487)	(0.5)	(0.0)	-	-	(0.5)	-	(0.5)	(0.5)
27.	Communication structures & equip. (488)	(1.4)	(0.2)	1.8	-	0.1	-	0.1	(0.6)
28.	Computer equipment (490)	(31.6)	(1.9)	7.2	-	(26.4)	-	(26.4)	(29.8)
29.	Software Aquired/Developed (491)	(229.9)	(6.9)	23.5	-	(213.3)	-	(213.3)	(230.5)
30.	CIS (491)	(127.1)	(18.3)	124.1	-	(21.3)	-	(21.3)	(109.9)
31.	WAMS (489)	(38.4)	(8.1)	-	-	(46.4)	-	(46.4)	(42.0)
32.	Sub-Total	(505.5)	(45.2)	158.0	(0.1)	(392.7)	0.3	(392.5)	(493.6)
	EGD Rate Zone Plant held for future use								
33.	Inactive services (102)	(1.4)	(0.0)	-	-	(1.4)	-	(1.4)	(1.4)
34.	EGD Rate Zone Total	(3,658.8)	(308.0)	129.1	46.0	(3,791.7)	3.6	(3,788.1)	(3,714.3)
	Union Rate Zones Intangible Plant								
35.	Franchises and consents (401)	(0.9)	(0.1)	-	-	(1.0)	-	(1.0)	(1.0)
36.	Other intangible plant (402)	(0.3)	(0.2)	-	-	(0.5)	-	(0.5)	(0.3)
37.	Sub-Total	(1.2)	(0.3)	-	-	(1.5)	-	(1.5)	(1.3)

	Union Rate Zones Local Storage Plant								
38.	Structures and improvements (442)	(2.7)	(0.1)	-	0.2	(2.7)	-	(2.7)	(2.7)
39.	Gas holders - storage (443)	(3.8)	(0.1)	-	-	(3.9)	-	(3.9)	(3.9)
40.	Gas holders - equipment (443)	(10.3)	(0.7)	-	0.0	(11.0)	-	(11.0)	(10.6)
41.	Regulatory Overheads	(0.5)	(0.1)	-	-	(0.6)	-	(0.6)	(0.5)
42.	Sub-Total	(17.3)	(1.0)	-	0.2	(18.2)	-	(18.2)	(17.8)
	Union Rate Zones Underground Storage Plant								
43.	Land rights (451)	(18.1)	(0.7)	-	-	(18.8)	-	(18.8)	(18.4)
44.	Structures and improvements (452)	(42.1)	(1.7)	-	-	(43.9)	-	(43.9)	(43.0)
45.	Wells (453)	(33.0)	(1.2)	-	-	(34.2)	-	(34.2)	(33.6)
46.	Field Lines (455)	(28.4)	(1.2)	-	-	(29.6)	-	(29.6)	(29.1)
47.	Compressor equipment (456)	(155.6)	(12.6)	-	0.0	(168.2)	-	(168.2)	(161.9)
48.	Measuring & regulating equipment (457)	(44.3)	1.2	-	0.1	(43.0)	-	(43.0)	(45.4)
49.	Regulatory Overheads	(3.6)	(0.5)	-	-	(4.1)	-	(4.1)	(4.0)
50.	Sub-Total	(325.1)	(16.7)	-	0.1	(341.7)	-	(341.7)	(335.4)
	Union Rate Zones Transmission Plant								
51.	Land rights (461)	(18.1)	(1.2)	-	-	(19.3)	-	(19.3)	(18.7)
52.	Structures & improvements (462/463/464)	(43.5)	(3.4)	-	0.1	(46.8)	-	(46.8)	(45.1)
53.	Mains (465)	(662.8)	(38.9)	4.1	0.4	(697.3)	-	(697.3)	(682.0)
54.	Compressor equipment (466)	(293.9)	(30.5)	-	0.0	(324.3)	-	(324.3)	(309.1)
55.	Measuring & regulating equipment (467)	(104.0)	(12.2)	-	0.0	(116.2)	-	(116.2)	(108.4)
56.	Regulatory Overheads	(22.8)	(5.2)	-	-	(28.0)	-	(28.0)	(25.3)
57.	Sub-Total	(1,145.1)	(91.4)	4.1	0.5	(1,231.9)	-	(1,231.9)	(1,188.6)
	Union Rate Zones Distribution Plant - Southern Operations								
58.	Land rights (471)	(2.3)	(0.1)	-	-	(2.4)	-	(2.4)	(2.3)
59.	Structures and improvements (472)	(44.3)	(3.1)	-	0.0	(47.4)	-	(47.4)	(45.8)
60.	Services - metallic (473)	(107.3)	(3.6)	0.3	1.8	(108.8)	-	(108.8)	(108.7)
61.	Services - plastic (473)	(428.6)	(24.5)	1.8	6.8	(444.5)	-	(444.5)	(437.2)
62.	Regulators (474)	(41.7)	(4.8)	5.8	-	(40.8)	-	(40.8)	(43.1)
63.	House regulators & meter installations (474)	(30.1)	(2.2)	-	0.0	(32.3)	-	(32.3)	(31.2)
64.	Mains - metallic (475)	(363.6)	(16.8)	0.9	3.6	(375.9)	-	(375.9)	(370.5)
65.	Mains - plastic (475)	(285.4)	(16.6)	0.5	0.5	(300.9)	-	(300.9)	(293.3)
66.	Measuring & regulating equipment (477)	(21.5)	(2.4)	-	0.3	(23.6)	-	(23.6)	(22.4)
67.	Meters (478)	(106.8)	(14.5)	3.3	(0.1)	(118.0)	-	(118.0)	(112.0)
68.	Regulatory Overheads	(44.5)	(9.4)	-	-	(53.9)	-	(53.9)	(48.9)
69.	Sub-Total	(1,476.1)	(98.1)	12.7	13.1	(1,548.5)	-	(1,548.5)	(1,515.5)
	Union Rate Zones Distribution Plant - Northern & Eastern Operations								
70.	Land rights intangibles (471)	(4.3)	(0.2)	-	-	(4.5)	-	(4.5)	(4.4)
71.	Structures and improvements (472)	(26.7)	(1.7)	-	-	(28.3)	-	(28.3)	(27.5)
72.	Services - metallic (473)	(78.6)	(3.6)	0.2	0.5	(81.4)	-	(81.4)	(80.2)
73.	Services - plastic (473)	(219.0)	(12.9)	0.8	0.4	(230.7)	-	(230.7)	(225.3)
74.	Regulators (474)	(15.6)	(1.8)	2.1	(0.0)	(15.3)	-	(15.3)	(16.1)
75.	House regulators & meter installations (474)	(16.5)	(1.2)	-	0.0	(17.7)	-	(17.7)	(17.1)
76.	Mains - metallic (475)	(348.4)	(20.7)	0.8	1.5	(366.9)	-	(366.9)	(358.3)
77.	Mains - plastic (475)	(114.2)	(5.7)	0.2	0.0	(119.6)	-	(119.6)	(117.0)
78.	Measuring & regulating equipment (477)	(77.3)	(5.7)	-	0.3	(82.7)	-	(82.7)	(80.0)
79.	Meters (478)	(25.5)	(3.9)	0.9	0.0	(28.6)	-	(28.6)	(26.9)
80.	Regulatory Overheads	(24.8)	(5.2)	-	-	(30.0)	-	(30.0)	(27.3)
81.	Sub-Total	(950.9)	(62.7)	5.0	2.7	(1,005.9)	-	(1,005.9)	(980.1)
	Union Rate Zones General Plant								
82.	Structures & improvements (482)	(15.7)	(1.6)	-	-	(17.3)	-	(17.3)	(16.5)
83.	Office furniture and equipment (483)	(6.4)	(0.7)	0.9	0.0	(6.2)	-	(6.2)	(6.6)
84.	Office equipment - computers (483)	(90.5)	(25.2)	69.1	-	(46.6)	-	(46.6)	(96.3)
85.	Transportation equipment (484)	(48.1)	(8.7)	5.1	(1.2)	(52.8)	-	(52.8)	(50.8)
86.	Heavy work equipment (485)	(5.3)	(1.3)	0.5	-	(6.2)	-	(6.2)	(5.8)
87.	Tools and work equipment (486)	(20.8)	(2.4)	6.1	-	(17.2)	-	(17.2)	(21.1)
88.	NGV fuel equipment (487)	(1.4)	(0.1)	-	-	(1.6)	-	(1.6)	(1.5)
89.	Communication equipment (488)	(9.4)	(0.7)	4.9	-	(5.1)	-	(5.1)	(8.5)
90.	Regulatory Overheads	(31.0)	(6.3)	9.8	-	(27.5)	-	(27.5)	(33.9)
91.	Sub-Total	(228.7)	(47.1)	96.5	(1.2)	(180.5)	-	(180.5)	(241.0)
92.	Union Rate Zones Total	(4,144.3)	(317.4)	118.3	15.4	(4,328.1)	-	(4,328.1)	(4,279.7)
93.	EGI Total	(7,803.2)	(625.4)	247.4	61.4	(8,119.8)	3.6	(8,116.2)	(7,994.0)

EGI WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2021 ACTUAL

Line No.		Col. 1 Materials and Supplies	Col. 2 ABC Receivable	Col. 3 Customer Security Deposits	Col. 4 Prepaid Expenses	Col. 5 Balancing Gas	Col. 6 Gas in Storage	Col. 7 Working Cash Allowance	Col. 8 Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	87.5	(14.7)	(78.3)	(0.4)	59.5	657.3	20.9	731.8
2.	January 31	88.2	(9.5)	(71.3)	(11.0)	59.5	558.1	20.9	634.7
3.	February	88.6	(15.2)	(71.2)	(4.0)	59.5	426.1	20.9	504.6
4.	March	89.8	(34.9)	(71.3)	3.7	59.5	325.3	20.9	392.8
5.	April	92.4	(26.5)	(71.2)	7.0	59.5	308.0	20.9	389.9
6.	May	92.8	(25.6)	(72.4)	6.7	59.5	360.6	20.9	442.4
7.	June	94.4	(31.1)	(66.2)	7.5	59.5	475.2	20.9	560.1
8.	July	95.7	(15.3)	(66.6)	4.0	59.5	569.9	20.9	668.0
9.	August	98.4	(9.2)	(66.7)	9.0	59.5	664.2	20.9	776.0
10.	September	91.9	(12.2)	(66.0)	11.8	59.5	762.0	20.9	867.8
11.	October	93.4	2.2	(65.8)	13.3	59.5	984.0	20.9	1,107.4
12.	November	94.8	3.5	(65.9)	8.6	59.5	926.4	20.9	1,047.7
13.	December	91.4	(10.0)	(65.1)	(0.8)	59.5	895.1	20.9	990.9
14.	Avg. of monthly avgs.	92.5	(15.5)	(68.9)	4.7	59.5	594.7	20.9	687.7

EGI SUMMARY OF CAPITAL STRUCTURE & COST OF CAPITAL
2021 ACTUAL

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5 (Col. 1x Col. 3)
Line No.		Utility Capital Structure Principal	Utility Capital Structure Component	Cost Rate	Return Component	Interest & Return
		($Millions)	%	%	%	($Millions)
1.	Long and Medium-Term Debt	8,505.3	59.83	4.37	2.612	371.3
2.	Short-Term Debt	593.1	4.17	0.31	0.013	1.9
3.	Total Debt	9,098.3	64.00		2.625	
4.	Preference Shares	-	-	-	-	-
5.	Common Equity	5,117.8	36.00	9.84	3.542	503.6
6.	Total Rate Base	14,216.1	100.00		6.167	876.7

CALCULATION OF COST RATES
FOR EGI CAPITAL STRUCTURE COMPONENTS
2021 ACTUAL

Line No.			Col. 1 Average of Monthly Averages ($Millions)	Col. 2	Col. 3 Carrying Cost ($Millions)
	Long and Medium-Term Debt				
1.	Debt Summary		8,833.5		381.1
2.	Unamortized Finance Costs		(103.3)		-
3.	(Profit)/Loss on Redemption		-		-
4.			8,730.2		381.1
5.	Percentage Allocation of Debt to Unregulated	2.58%	(224.9)		(9.8)
6.	Net Regulated Long and Medium-Term Debt		8,505.3		371.3
7.	Calculated Cost Rate			4.37%	
	Short-Term Debt				
8.	Calculated Cost Rate			0.31%	
	Preference Shares				
9.	Preference Share Summary		-		-
10.	Unamortized Finance Costs		-		-
11.	(Profit)/Loss on Redemption		-		-
12.			-		-
13.	Calculated Cost Rate			0.00%	
	Common Equity				
14.	Board Formula ROE			8.34%	
15.	Threshold before earnings sharing			1.50%	
16.	ROE for earnings sharing determination			9.84%	

EGI SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2021 ACTUAL

			Col. 1	Col. 2	Col. 3
Line No.	Coupon Rate	Maturity Date	Average of Monthly Averages Principal	Effective Cost Rate	Carrying Cost
			($Millions)		($Millions)
Medium Term Notes					
1.	8.85%	October 2, 2025	20.0	8.97%	1.8
2.	7.60%	October 29, 2026	100.0	8.09%	8.1
3.	6.65%	November 3, 2027	100.0	6.71%	6.7
4.	6.10%	May 19, 2028	100.0	6.16%	6.2
5.	6.05%	July 5, 2023	100.0	6.38%	6.4
6.	6.90%	November 15, 2032	150.0	6.95%	10.4
7.	6.16%	December 16, 2033	150.0	6.18%	9.3
8.	5.21%	February 25, 2036	300.0	5.18%	15.5
9.	4.77%	December 17, 2021	167.7	5.31%	8.9
10.	4.95%	November 22, 2050	200.0	4.99%	10.0
11.	4.95%	November 22, 2050	100.0	4.73%	4.7
12.	4.50%	November 23, 2043	200.0	4.20%	8.4
13.	3.15%	August 22, 2024	215.0	3.24%	7.0
14.	4.00%	August 22, 2044	215.0	3.89%	8.4
15.	4.00%	August 22, 2044	170.0	4.44%	7.5
16.	3.31%	September 11, 2025	400.0	3.62%	14.5
17.	2.50%	August 5, 2026	300.0	3.42%	10.3
18.	3.51%	November 29, 2047	300.0	3.53%	10.6
19.	2.37%	August 9, 2029	400.0	3.23%	12.9
20.	3.01%	August 9, 2049	300.0	3.03%	9.1
21.	2.90%	April 1, 2030	600.0	3.41%	20.4
22.	3.65%	April 1, 2050	600.0	3.67%	22.0
23.	2.35%	September 1, 2031	138.5	2.94%	4.1
24.	3.20%	September 1, 2051	124.0	3.22%	4.0
25.	8.65%	November 10, 2025	125.0	8.77%	11.0
26.	5.46%	September 11, 2036	165.0	5.49%	9.1
27.	4.85%	April 25, 2022	125.0	4.91%	6.1
28.	6.05%	September 2, 2038	300.0	6.10%	18.3
29.	5.20%	July 23, 2040	250.0	5.27%	13.2
30.	4.88%	June 21, 2041	300.0	4.92%	14.8
31.	3.79%	July 10, 2023	250.0	3.87%	9.7
32.	2.76%	June 2, 2021	83.3	2.85%	2.4
33.	4.20%	June 2, 2044	250.0	4.24%	10.6
34.	4.20%	June 2, 2044	250.0	4.27%	10.7
35.	3.19%	September 17, 2025	200.0	3.26%	6.5
36.	2.81%	June 1, 2026	250.0	2.87%	7.2
37.	3.80%	June 1, 2046	250.0	3.84%	9.6
38.	3.59%	November 22, 2047	250.0	3.64%	9.1
39.	2.88%	November 22, 2027	250.0	2.95%	7.4
40.			8,748.5		372.7
Long-Term Debentures					
41.	9.85%	December 2, 2024	85.0	9.910%	8.4
42.			85.0		8.4
43.	Total Term Debt		8,833.5		381.1

EGI UNAMORTIZED DEBT DISCOUNT AND EXPENSE
AVERAGE OF MONTHLY AVERAGES
2021 ACTUAL

Line No.		Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	100.9
2.	January 31	99.8
3.	February	98.8
4.	March	97.7
5.	April	96.7
6.	May	95.6
7.	June	94.6
8.	July	93.5
9.	August	92.5
10.	September	121.8
11.	October	120.5
12.	November	119.2
13.	December	118.1
14.	Average of Monthly Averages	103.3

RECONCILIATION OF AUDITED EGI INCOME (PER FINANCIAL STATEMENTS)
TO CORPORATE INCOME FOR UTILITY INCOME DETERMINATION PURPOSES
2021 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	3,996.4	4,513.2		
2.	Storage, transportation and other	896.7	-		
3.	Transportation	-	143.0		
4.	Storage	-	159.7		
5.	Other operating revenue	-	64.3		
6.	Other Income	42.9	7.2		
7.	Total operating revenue	4,936.0	4,887.4	(48.6)	(a)
	Operating Expenses				
8.	Gas Costs	2,146.2	2,146.2	-	
9.	Operation and maintenance	1,105.1	938.6	(166.5)	(b)
10.	Depreciation and amortization expense	676.8	676.8	-	
11.	Fixed financing costs	-	6.3	6.3	(c)
12.	Municipal and other taxes	-	117.9	117.9	(d)
13.	Cost of service	3,928.1	3,885.8	(42.3)	
14.	Income before interest and income taxes	1,007.9	1,001.6	(6.3)	
15.	Interest and financing expenses	393.9	-	(393.9)	(e)
16.	Income before income taxes	614.0	1,001.6	387.6	
17.	Income taxes	62.9	-	(62.9)	(f)
18.	Net Income	551.1	1,001.6	450.5	

Col. 2 - Corporate income as reported in Exhibit B, Tab 1, Schedule 2, Column 1

a)	**Audited Total Operating Revenue**	4,936.0
	Reclassify pension related other revenue to O&M	(36.0)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(12.8)
	Reclassify other expenses out of other income to O&M	0.2
	Corporate Total Operating Revenue	4,887.4
b)	**Audited Operation and Maintenance**	1,105.1
	Reclassify pension related other revenue to O&M	(36.0)
	Reclassify Municipal & Property Taxes out of O&M	(117.9)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(12.8)
	Reclassify other expenses out of other income to O&M	0.2
	Corporate Operation and Maintenance	938.6
c)	**Audited Fixed Financing Costs**	-
	Reclassify fixed financing costs from interest and financing expenses	6.3
	Corporate Fixed Financing Costs	6.3
d)	**Audited Municipal and Other Taxes**	-
	Reclassify Municipal and other taxes included within O&M costs	117.9
	Corporate Municipal and Other Taxes	117.9
e)	**Audited Interest and Financing expenses**	393.9
	Reclassify fixed financing costs from interest and financing expenses	(6.3)
	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure	(387.6)
	Corporate Interest and Financing expenses	-
f)	**Audited Income Taxes**	62.9
	Elimination of corporate income taxes which will be calculated on a utility stand-alone basis	(62.9)
	Corporate Income Taxes	-

DELIVERY REVENUE BY SERVICE TYPE, RATE CLASS AND SERVICE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2021

Line No.		Col. 1 Sales	Col. 2 ABC-T	Col. 3 ABC-Unbundled	Col. 4 Bundled-T	Col. 5 T-Service	Col. 6 Total
		Revenues ($ Millions)					
1	General Service						
2	Rate 1	920.6	16.4	0.0	(0.0)	0.0	937.0
3	Rate 6	288.5	78.0	0.0	28.4	0.0	394.9
4	Rate 9	0.0	0.0	0.0	0.0	0.0	0.0
5	**Total EGD Rate Zone**	**1,209.1**	**94.4**	**0.0**	**28.4**	**0.0**	**1,331.8**
6	Rate M1	463.7	16.9	0.0	1.4	0.0	482.0
7	Rate M2	33.0	20.7	0.0	14.2	0.0	67.9
8	Rate 01	173.9	7.4	0.0	0.9	0.0	182.2
9	Rate 10	10.5	5.8	0.0	4.4	0.2	21.0
10	**Total Union Rate Zones**	**681.1**	**50.9**	**0.0**	**20.9**	**0.2**	**753.1**
11	**Total General Service**	**1,890.2**	**145.3**	**0.0**	**49.3**	**0.2**	**2,084.9**
12	Wholesale - Utility						
13	Rate M9	0.7	0.0	0.0	1.0	0.0	1.7
14	Rate M10	0.0	0.0	0.0	0.0	0.0	0.0
15	**Total Wholesale - Utility**	**0.7**	**0.0**	**0.0**	**1.0**	**0.0**	**1.7**
16	Contract Sales						
17	Rate 100	0.6	0.3	0.0	1.1	0.0	2.0
18	Rate 110	2.6	4.6	0.0	24.0	0.0	31.2
19	Rate 115	0.0	0.0	0.0	5.4	0.0	5.4
20	Rate 125	0.0	0.0	0.0	0.0	11.9	11.9
21	Rate 135	0.2	0.2	0.0	1.2	0.0	1.5
22	Rate 145	0.0	0.1	0.0	1.5	0.0	1.7
23	Rate 170	0.1	0.2	0.0	2.6	0.0	2.9
24	Rate 200	3.2	0.0	0.0	1.6	0.0	4.9
25	Rate 300	0.0	0.0	0.0	0.0	0.1	0.1
26	Rate 315	0.0	0.0	0.0	0.0	0.0	0.0
27	**Total EGD Rate Zone**	**6.7**	**5.4**	**0.0**	**37.4**	**11.9**	**61.5**
28	Rate M4	4.0	2.3	0.0	26.5	0.0	32.8
29	Rate M7	2.3	0.5	0.0	20.7	0.0	23.4
30	Rate 20	0.8	0.1	0.0	3.0	20.7	24.7
31	Rate 100	0.0	0.0	0.0	0.0	11.5	11.5
32	Rate T-1	0.0	0.0	0.0	0.0	13.9	13.9
33	Rate T-2	0.0	0.0	0.0	0.0	75.9	75.9
34	Rate T-3	0.0	0.0	0.0	0.0	7.2	7.2
35	Rate M5	0.2	0.2	0.0	2.2	0.0	2.5
36	Rate 25	2.7	0.0	0.0	0.4	2.7	5.8
37	Rate 30	0.0	0.0	0.0	0.0	0.0	0.0
38	**Total Union Rate Zones**	**9.9**	**3.1**	**0.0**	**52.8**	**131.9**	**197.7**
39	**Total Contract Sales**	**16.6**	**8.5**	**0.0**	**90.3**	**143.9**	**259.2**
40	**Subtotal**	**1,907.5**	**153.8**	**0.0**	**140.6**	**144.1**	**2,345.9**
41	**Accounting Adjustments:**						
42	EGI Tax Variance						(18.0)
43	EGI Accounting Policy Change						(16.2)
44	EGD Average Use / Normalized Average Consumption						9.9
45	EGD Dawn Access COS (DACDA)						2.0
46	EGD Incremental Capital Module						0.2
47	EGD LRAM						0.0
48	EGD Federal Carbon Program						0.7
49	EGD Greenhouse Gas Emissions Administration						0.1
50	Union Average Use / Normalized Average Consumption						16.0
51	Union Incremental Capital Module						(14.0)
52	Union Capital Pass-through						(4.4)
53	Union LRAM						0.7
54	Union Federal Carbon Program						1.5
55	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues						(17.2)
	Total Utility Revenue						**2,307.3**

DELIVERY REVENUE BY SERVICE TYPE, RATE CLASS AND SERVICE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2020

Line No.		Col. 1 Sales	Col. 2 ABC-T	Col. 3 ABC-Unbundled	Col. 4 Bundled-T	Col. 5 T-Service	Col. 6 Total
				Revenues ($ Millions)			
1	General Service						
2	Rate 1	912.6	19.9	0.0	0.0	0.1	932.6
3	Rate 6	284.9	81.3	0.0	0.0	28.4	394.6
4	Rate 9	0.0	0.0	0.0	0.0	0.0	0.0
5	**Total EGD Rate Zone**	**1,197.5**	**101.2**	**0.0**	**0.0**	**28.5**	**1,327.3**
6	Rate M1	448.2	18.7	(0.0)	1.3	0.0	468.1
7	Rate M2	33.5	21.2	0.0	14.3	0.0	69.0
8	Rate 01	171.7	8.5	0.0	1.0	0.0	181.2
9	Rate 10	10.7	6.1	0.0	5.2	0.3	22.4
10	**Total Union Rate Zones**	**664.1**	**54.5**	**(0.0)**	**21.8**	**0.3**	**740.7**
11	**Total General Service**	**1,861.6**	**155.7**	**(0.0)**	**21.8**	**28.8**	**2,068.0**
12	Wholesale - Utility						
13	Rate M9	0.6	0.0	0.0	0.9	0.0	1.6
14	Rate M10	0.0	0.0	0.0	0.0	0.0	0.0
15	**Total Wholesale - Utility**	**0.7**	**0.0**	**0.0**	**0.9**	**0.0**	**1.6**
16	Contract Sales						
17	Rate 100	0.6	0.2	0.0	0.0	0.7	1.5
18	Rate 110	2.6	2.8	0.0	0.0	21.1	26.5
19	Rate 115	0.3	0.0	0.0	0.0	5.1	5.4
20	Rate 125	0.0	0.0	11.5	0.0	0.0	11.5
21	Rate 135	0.1	0.1	0.0	0.0	1.1	1.3
22	Rate 145	0.0	0.1	0.0	0.0	1.0	1.1
23	Rate 170	0.1	0.2	0.0	0.0	2.3	2.5
24	Rate 200	3.1	0.0	0.0	0.0	1.4	4.5
25	Rate 300	0.0	0.0	0.1	0.0	0.0	0.1
26	Rate 315	0.0	0.0	0.0	0.0	0.0	0.0
27	**Total EGD Rate Zone**	**6.7**	**3.4**	**11.6**	**0.0**	**32.7**	**54.4**
28	Rate M4	3.5	1.7	0.0	26.4	0.0	31.6
29	Rate M7	1.6	0.3	0.0	16.8	0.0	18.8
30	Rate 20 Storage	0.0	0.0	0.0	0.0	0.0	0.0
31	Rate 20 Transportation	0.9	0.1	0.0	2.7	21.2	25.0
32	Rate 100 Storage	0.0	0.0	0.0	0.0	0.0	0.0
33	Rate 100 Transportation	0.0	0.0	0.0	0.0	11.3	11.3
34	Rate T-1 Storage	0.0	0.0	0.0	0.0	1.4	1.4
35	Rate T-1 Transportation	0.0	0.0	0.0	0.0	12.2	12.2
36	Rate T-2 Storage	0.0	0.0	0.0	0.0	7.2	7.2
37	Rate T-2 Transportation	0.0	0.0	0.0	0.0	66.9	66.9
38	Rate T-3 Storage	0.0	0.0	0.0	0.0	1.4	1.4
39	Rate T-3 Transportation	0.0	0.0	0.0	0.0	5.8	5.8
40	Rate M5	0.1	0.1	0.0	2.0	0.0	2.3
41	Rate 25	1.1	0.0	0.0	0.0	2.8	3.8
42	Rate 30	0.0	0.0	0.0	0.0	0.0	0.0
43	**Total Union Rate Zones**	**7.3**	**2.3**	**0.0**	**47.9**	**130.1**	**187.6**
44	**Total Contract Sales**	**14.0**	**5.7**	**11.6**	**47.9**	**162.7**	**241.9**
45	**Subtotal**	**1,876.3**	**161.4**	**11.6**	**70.7**	**191.6**	**2,311.5**
46	**Accounting Adjustments:**						
47	EGI Tax Variance						(13.4)
48	EGI Accounting Policy Change						(14.0)
49	EGD Average Use/ Normalized Average Consumption						(2.5)
50	EGD Dawn Access Cost						2.1
51	EGD Incremental Capital Module						(0.3)
52	EGD Transactional Services Revenue						12.0
53	EGD LRAM						0.0
54	EGD Federal Carbon Program						0.6
55	EGD Greenhouse Gas Emissions Administration						0.2
56	EGD Reverse 2019 Gas Supply Plan Cost Consequences reversed						(3.9)
57	EGD Elimination of 2019 Gas Supply Plan Cost Consequences reversal						3.9
58	Union Average Use/ Normalized Average Consumption						6.7
59	Union Parkway Obligation Rate Variance						0.0
60	Union Incremental Capital Module						(5.6)
61	Union Capital Pass-through						(1.1)
62	Union LRAM						1.4
63	Union Federal Carbon Program						1.2
64	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues						(17.7)
66	Miscellaneous						0.7
	Total Utility Revenue						**2,281.9**

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2021

Line No.		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Customer Meters			Throughput Volumes (10^3M^3)			Revenues ($ Millions)		
		Sales	T-Service	Total	Sales	T-Service	Total	Sales	T-Service	Total
1	General Service									
2	Rate 1	2,064,173	34,054	2,098,227	4,665,992	82,730	4,748,722	1,749.7	18.5	1,768.3
3	Rate 6	147,546	22,416	169,962	2,740,101	1,698,331	4,438,432	775.8	144.3	920.1
4	Rate 9	2	0	2	3	0	3	0.0	0.0	0.0
5	**Total EGD Rate Zone**	**2,211,721**	**56,470**	**2,268,191**	**7,406,097**	**1,781,061**	**9,187,158**	**2,525.6**	**162.8**	**2,688.3**
6	Rate M1	1,140,908	29,855	1,170,763	2,728,007	169,080	2,897,087	853.1	18.3	871.4
7	Rate M2	4,749	3,206	7,955	526,743	587,121	1,113,864	109.2	35.0	144.2
8	Rate 01	351,562	10,059	361,621	871,182	58,759	929,941	364.2	12.8	377.1
9	Rate 10	1,369	878	2,247	148,728	163,067	311,794	40.9	20.0	60.9
10	**Total Union Rate Zones**	**1,498,588**	**43,998**	**1,542,586**	**4,274,660**	**978,026**	**5,252,686**	**1,367.4**	**86.1**	**1,453.5**
11	**Total General Service**	**3,710,309**	**100,468**	**3,810,777**	**11,680,756**	**2,759,087**	**14,439,844**	**3,893.0**	**248.9**	**4,141.9**
12	Wholesale - Utility									
13	Rate M9	1	3	4	15,903	74,193	90,096	3.0	1.0	4.0
14	Rate M10	2	0	2	320	0	320	0.1	0.0	0.1
15	**Total Wholesale - Utility**	**3**	**3**	**6**	**16,223**	**74,193**	**90,415**	**3.1**	**1.0**	**4.1**
16	Contract Sales									
17	Rate 100	6	10	16	12,899	21,095	33,994	2.9	1.8	4.7
18	Rate 110	110	305	415	83,260	1,018,629	1,101,890	16.6	40.4	57.0
19	Rate 115	2	15	17	1,002	386,695	387,697	0.2	8.2	8.3
20	Rate 125	0	4	4	0	707,660	707,660	0.0	11.9	11.9
21	Rate 135	7	35	42	2,624	60,488	63,112	0.6	1.6	2.2
22	Rate 145	5	15	20	0	24,785	24,785	0.0	1.9	1.9
23	Rate 170	1	22	23	6,302	249,399	255,701	1.1	1.2	2.3
24	Rate 200	1	0	1	137,779	54,230	192,010	27.8	2.4	30.2
25	Rate 300	0	2	2	0	269	269	0.0	0.1	0.1
26	Rate 315	0	0	0	0	0	0	0.0	0.0	0.0
27	**Total EGD Rate Zone**	**132**	**408**	**540**	**243,868**	**2,523,251**	**2,767,118**	**49.2**	**69.4**	**118.6**
28	Rate M4	37	190	227	56,304	554,504	610,808	12.0	28.8	40.8
29	Rate M7	5	56	61	31,987	654,366	686,353	6.7	21.2	27.9
30	Rate 20	5	54	59	8,464	629,136	637,600	2.9	30.6	33.5
31	Rate 100	0	12	12	0	958,587	958,587	0.0	11.5	11.5
32	Rate T-1	0	39	39	0	453,007	453,007	0.0	13.9	13.9
33	Rate T-2	0	25	25	0	4,700,474	4,700,474	0.0	76.0	76.0
34	Rate T-3	0	1	1	0	241,187	241,187	0.0	7.2	7.2
35	Rate M5	4	34	38	4,043	59,468	63,511	0.8	2.3	3.1
36	Rate 25	37	30	67	79,188	64,709	143,898	15.6	3.1	18.8
37	Rate 30	0	0	0	0	0	0	0.0	0.0	0.0
38	**Total Union Rate Zones**	**88**	**441**	**529**	**179,987**	**8,315,439**	**8,495,425**	**38.0**	**194.7**	**232.7**
39	**Total Contract Sales**	**220**	**849**	**1,069**	**423,854**	**10,838,690**	**11,262,544**	**87.2**	**264.1**	**351.3**
40	**Subtotal**	**3,710,532**	**101,320**	**3,811,852**	**12,120,833**	**13,671,970**	**25,792,803**	**3,983.3**	**514.0**	**4,497.3**
41	**Accounting Adjustments:**									
42	EGI Tax Variance									(18.0)
43	EGI Accounting Policy Change									(16.2)
44	EGD Average Use / Normalized Average Consumption									15.4
45	EGD Dawn Access COS (DACDA)									2.0
46	EGD Incremental Capital Module									0.2
47	EGD LRAM									0.0
48	EGD Federal Carbon Program									0.7
49	EGD Greenhouse Gas Emissions Administration									0.1
50	EGD Transactional Services Revenue									12.0
51	Union Average Use / Normalized Average Consumption									19.0
52	Union Incremental Capital Module									(14.0)
53	Union Capital Pass-through									(4.4)
54	Union LRAM									0.7
55	Union Federal Carbon Program									1.5
56	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.2)
57	Miscellaneous									1.4
58	**Total Utility Revenue**									**4,480.6**

WEATHER NORMALIZED CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2021

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Customer Meters			Throughput Volumes (10^3M^3)			Revenues ($ Millions)		
Line No.		Sales	T-Service	Total	Sales	T-Service	Total	Sales	T-Service	Total
1	General Service									
2	Rate 1	2,064,173	34,054	2,098,227	4,930,993	86,477	5,017,470	1,810.6	18.9	1,829.5
3	Rate 6	147,546	22,416	169,962	2,899,533	1,806,248	4,705,781	807.3	152.6	959.9
4	Rate 9	2	0	2	3	0	3	0.0	0.0	0.0
5	**Total EGD Rate Zone**	**2,211,721**	**56,470**	**2,268,191**	**7,830,529**	**1,892,725**	**9,723,254**	**2,617.9**	**171.6**	**2,789.5**
6	Rate M1	1,140,908	29,855	1,170,763	2,901,101	179,808	3,080,909	881.4	18.7	900.1
7	Rate M2	4,749	3,206	7,955	559,108	623,195	1,182,303	114.6	36.8	151.4
8	Rate 01	351,562	10,059	361,621	935,043	63,066	998,109	381.5	13.4	395.0
9	Rate 10	1,369	878	2,247	157,870	173,090	330,960	43.0	21.1	64.1
10	**Total Union Rate Zones**	**1,498,588**	**43,998**	**1,542,586**	**4,553,121**	**1,039,160**	**5,592,281**	**1,420.5**	**90.1**	**1,510.6**
11	**Total General Service**	**3,710,309**	**100,468**	**3,810,777**	**12,383,650**	**2,931,885**	**15,315,535**	**4,038.4**	**261.6**	**4,300.1**
12	Wholesale - Utility									
13	Rate M9	1	3	4	15,903	74,193	90,096	3.0	1.0	4.0
14	Rate M10	2	0	2	320	0	320	0.1	0.0	0.1
15	**Total Wholesale - Utility**	**3**	**3**	**6**	**16,223**	**74,193**	**90,415**	**3.1**	**1.0**	**4.1**
16	Contract Sales									
17	Rate 100	6	10	16	12,899	21,095	33,994	2.9	1.8	4.7
18	Rate 110	110	305	415	83,587	1,020,335	1,103,922	16.7	40.4	57.1
19	Rate 115	2	15	17	1,011	386,733	387,744	0.2	8.2	8.4
20	Rate 125	0	4	4	0	707,660	707,660	0.0	11.9	11.9
21	Rate 135	7	35	42	2,624	60,488	63,112	0.6	1.6	2.2
22	Rate 145	5	15	20	29	24,912	24,941	0.0	1.9	1.9
23	Rate 170	1	22	23	6,302	250,441	256,744	1.1	1.3	2.3
24	Rate 200	1	0	1	145,763	54,230	199,994	29.1	2.4	31.5
25	Rate 300	0	2	2	0	269	269	0.0	0.1	0.1
26	Rate 315	0	0	0	0	0	0	0.0	0.0	0.0
27	**Total EGD Rate Zone**	**132**	**408**	**540**	**252,216**	**2,526,164**	**2,778,379**	**50.5**	**69.5**	**120.0**
28	Rate M4	37	190	227	56,304	554,504	610,808	12.0	28.8	40.8
29	Rate M7	5	56	61	31,987	654,366	686,353	6.7	21.2	27.9
30	Rate 20	5	54	59	8,464	629,136	637,600	2.9	30.6	33.5
31	Rate 100	0	12	12	0	958,587	958,587	0.0	11.5	11.5
32	Rate T-1	0	39	39	0	453,007	453,007	0.0	13.9	13.9
33	Rate T-2	0	25	25	0	4,700,474	4,700,474	0.0	76.0	76.0
34	Rate T-3	0	1	1	0	241,187	241,187	0.0	7.2	7.2
35	Rate M5	4	34	38	4,043	59,468	63,511	0.8	2.3	3.1
36	Rate 25	37	30	67	79,188	64,709	143,898	15.6	3.1	18.8
37	Rate 30	0	0	0	0	0	0	0.0	0.0	0.0
38	**Total Union Rate Zones**	**88**	**441**	**529**	**179,987**	**8,315,439**	**8,495,425**	**38.0**	**194.7**	**232.7**
39	**Total Contract Sales**	**220**	**849**	**1,069**	**432,202**	**10,841,602**	**11,273,805**	**88.5**	**264.1**	**352.7**
40	**Subtotal**	**3,710,532**	**101,320**	**3,811,852**	**12,832,075**	**13,847,680**	**26,679,755**	**4,130.0**	**526.8**	**4,656.8**
41	**Accounting Adjustments:**									
42	EGI Tax Variance									(18.0)
43	EGI Accounting Policy Change									(16.2)
44	EGD Average Use / Normalized Average Consumption									15.4
45	EGD Dawn Access COS (DACDA)									2.0
46	EGD Incremental Capital Module									0.2
47	EGD LRAM									0.0
48	EGD Federal Carbon Program									0.7
49	EGD Greenhouse Gas Emissions Administration									0.1
50	EGD Transactional Services Revenue									12.0
51	Union Average Use / Normalized Average Consumption									19.0
52	Union Incremental Capital Module									(14.0)
53	Union Capital Pass-through									(4.4)
54	Union LRAM									0.7
55	Union Federal Carbon Program									1.5
56	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.2)
57	Miscellaneous									1.4
58	**Total Utility Revenue**									**4,640.1**

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2020

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Customer Meters			Throughput Volumes (10^3M^3)			Revenues ($ Millions)		
Line No.		Sales	T-Service	Total	Sales	T-Service	Total	Sales	T-Service	Total
1	General Service									
2	Rate 1	2,020,078	44,454	2,064,531	4,789,664	104,740	4,894,404	1,618.2	28.4	1,646.6
3	Rate 6	145,283	23,801	169,084	2,810,280	1,840,046	4,650,326	663.4	187.5	850.9
4	Rate 9	2	0	2	127	0	127	0.0	0.0	0.0
5	**Total EGD Rate Zone**	**2,165,363**	**68,254**	**2,233,617**	**7,600,071**	**1,944,786**	**9,544,857**	**2,281.6**	**215.9**	**2,497.5**
6	Rate M1	1,128,040	35,176	1,163,216	2,815,940	187,938	3,003,878	772.5	19.9	792.4
7	Rate M2	4,324	3,571	7,895	571,025	633,316	1,204,341	99.3	35.6	134.8
8	Rate 01	347,480	12,515	359,995	913,225	69,511	982,736	340.3	14.5	354.8
9	Rate 10	1,156	982	2,138	155,265	187,391	342,656	37.1	21.9	58.9
10	**Total Union Rate Zones**	**1,481,000**	**52,244**	**1,533,244**	**4,455,454**	**1,078,157**	**5,533,611**	**1,249.1**	**91.9**	**1,341.0**
11	**Total General Service**	**3,646,363**	**120,498**	**3,766,861**	**12,055,525**	**3,022,943**	**15,078,468**	**3,530.7**	**307.8**	**3,838.5**
12	Wholesale - Utility									
13	Rate M9	1	3	4	16,236	72,529	88,765	2.5	0.9	3.5
14	Rate M10	2	0	2	360	0	360	0.1	0.0	0.1
15	**Total Wholesale - Utility**	**3**	**3**	**6**	**16,596**	**72,529**	**89,125**	**2.6**	**0.9**	**3.5**
16	Contract Sales									
17	Rate 100	2	7	9	9,142	10,969	20,111	1.8	1.2	3.0
18	Rate 110	57	279	335	71,781	909,360	981,141	9.6	36.4	45.9
19	Rate 115	1	19	20	728	377,311	378,039	0.2	7.6	7.8
20	Rate 125	4	0	4	0	523,436	523,436	0.0	11.4	11.4
21	Rate 135	5	36	40	1,785	63,502	65,287	0.4	1.6	2.0
22	Rate 145	3	19	22	628	22,768	23,396	0.3	1.3	1.6
23	Rate 170	3	18	21	4,843	242,587	247,430	0.6	0.7	1.4
24	Rate 200	1	0	1	137,358	52,115	189,473	23.1	2.4	25.5
25	Rate 300	2	0	2	0	262	262	0.0	0.1	0.1
26	Rate 315		0	0		0	0		0.0	0.0
27	**Total EGD Rate Zone**	**77**	**377**	**454**	**226,265**	**2,202,309**	**2,428,574**	**36.0**	**62.6**	**98.7**
28	Rate M4	35	201	236	56,325	565,055	621,380	9.9	28.1	38.0
29	Rate M7	4	49	53	28,488	589,884	618,372	4.7	17.1	21.8
30	Rate 20 Storage	0	0	0	0	0	0	0.0	2.5	2.5
31	Rate 20 Transportation	4	53	57	9,423	769,053	778,476	3.1	27.5	30.6
32	Rate 100 Storage	0	0	0	0	0	0	0.0	0.0	0.0
33	Rate 100 Transportation	0	12	12	0	996,605	996,605	0.0	11.3	11.3
34	Rate T-1 Storage	0	0	0	0	0	0	0.0	1.4	1.4
35	Rate T-1 Transportation	0	39	39	0	430,312	430,312	0.0	12.2	12.2
36	Rate T-2 Storage	0	0	0	0	0	0	0.0	7.2	7.2
37	Rate T-2 Transportation	0	25	25	0	4,017,975	4,017,975	0.0	66.9	66.9
38	Rate T-3 Storage	0	0	0	0	0	0	0.0	1.4	1.4
39	Rate T-3 Transportation	0	1	1	0	264,209	264,209	0.0	5.8	5.8
40	Rate M5	5	33	38	2,712	59,105	61,817	0.4	2.1	2.6
41	Rate 25	38	26	64	29,990	62,848	92,838	5.0	2.8	7.8
42	Rate 30	0	0	0	0	0	0	0.0	0.0	0.0
43	**Total Union Rate Zones**	**86**	**439**	**525**	**126,938**	**7,755,045**	**7,881,983**	**23.1**	**186.2**	**209.4**
44	**Total Contract Sales**	**163**	**816**	**979**	**353,203**	**9,957,354**	**10,310,557**	**59.2**	**248.8**	**308.0**
45	**Subtotal**	**3,646,529**	**121,318**	**3,767,846**	**12,425,324**	**13,052,825**	**25,478,150**	**3,592.5**	**557.6**	**4,150.1**
46	**Accounting Adjustments:**									
47	EGI Tax Variance									(13.4)
48	EGI Accounting Policy Change									(14.0)
49	EGD Average Use/ Normalized Average Consumption									(4.6)
50	EGD Dawn Access Cost									2.1
51	EGD Incremental Capital Module									(0.3)
52	EGD Transactional Services Revenue									12.0
53	EGD LRAM									0.0
54	EGD Federal Carbon Program									0.6
55	EGD Greenhouse Gas Emissions Administration									0.2
56	EGD Reverse 2019 Gas Supply Plan Cost Consequences reversed									(3.9)
57	EGD Elimination of 2019 Gas Supply Plan Cost Consequences reversal									3.9
58	Union Average Use/ Normalized Average Consumption									7.2
59	Union Parkway Obligation Rate Variance									0.0
60	Union Incremental Capital Module									(5.6)
61	Union Capital Pass-through									(1.1)
62	Union LRAM									1.4
63	Union Federal Carbon Program									1.2
64	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.7)
66	Miscellaneous									0.7
67	**Total Utility Revenue**									**4,118.8**

WEATHER NORMALIZED CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2020

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Customer Meters			Throughput Volumes (10^3M^3)			Revenues ($ Millions)		
Line No.		Sales	T-Service	Total	Sales	T-Service	Total	Sales	T-Service	Total
1	General Service									
2	Rate 1	2,020,078	44,454	2,064,531	4,925,067	107,556	5,032,623	1,650.3	28.7	1,679.0
3	Rate 6	145,283	23,801	169,084	2,919,935	1,887,608	4,807,543	686.1	190.5	876.6
4	Rate 9	2	0	2	127	0	127	0.0	0.0	0.0
5	**Total EGD Rate Zone**	**2,165,363**	**68,254**	**2,233,617**	**7,845,129**	**1,995,164**	**9,840,293**	**2,336.4**	**219.2**	**2,555.6**
6	Rate M1	1,128,040	35,176	1,163,216	2,966,369	197,978	3,164,348	801.4	20.3	821.7
7	Rate M2	4,324	3,571	7,895	595,912	660,918	1,256,830	104.1	36.9	141.0
8	Rate 01	347,480	12,515	359,995	954,899	72,683	1,027,582	352.7	15.0	367.6
9	Rate 10	1,156	982	2,138	160,473	193,677	354,151	38.4	22.6	61.0
10	**Total Union Rate Zones**	**1,481,000**	**52,244**	**1,533,244**	**4,677,654**	**1,125,257**	**5,802,911**	**1,296.5**	**94.8**	**1,391.3**
11	**Total General Service**	**3,646,363**	**120,498**	**3,766,861**	**12,522,783**	**3,120,421**	**15,643,204**	**3,632.9**	**314.0**	**3,946.9**
12	Wholesale - Utility									
13	Rate M9	1	3	4	16,236	72,529	88,765	2.5	0.9	3.5
14	Rate M10	2	0	2	360	0	360	0.1	0.0	0.1
15	**Total Wholesale - Utility**	**3**	**3**	**6**	**16,596**	**72,529**	**89,125**	**2.6**	**0.9**	**3.5**
16	Contract Sales									
17	Rate 100	2	7	9	9,142	10,969	20,111	1.8	1.2	3.0
18	Rate 110	57	279	335	71,936	910,575	982,511	9.6	36.4	46.0
19	Rate 115	1	19	20	730	377,426	378,156	0.2	7.6	7.8
20	Rate 125	4	0	4	0	523,436	523,436	0.0	11.4	11.4
21	Rate 135	5	36	40	1,785	63,502	65,287	0.4	1.6	2.0
22	Rate 145	3	19	22	628	22,937	23,565	0.3	1.3	1.6
23	Rate 170	3	18	21	4,847	243,184	248,031	0.6	0.7	1.4
24	Rate 200	1	0	1	142,758	52,433	195,190	24.0	2.4	26.4
25	Rate 300	2	0	2	0	262	262	0.0	0.1	0.1
26	Rate 315		0	0		0	0		0.0	0.0
27	**Total EGD Rate Zone**	**77**	**377**	**454**	**231,825**	**2,204,724**	**2,436,549**	**36.9**	**62.7**	**99.6**
28	Rate M4	35	201	236	56,325	565,055	621,380	9.9	28.1	38.0
29	Rate M7	4	49	53	28,488	589,884	618,372	4.7	17.1	21.8
30	Rate 20 Storage	0	0	0	0	0	0	0.0	2.5	2.5
31	Rate 20 Transportation	4	53	57	9,423	769,053	778,476	3.1	27.5	30.6
32	Rate 100 Storage	0	0	0	0	0	0	0.0	0.0	0.0
33	Rate 100 Transportation	0	12	12	0	996,605	996,605	0.0	11.3	11.3
34	Rate T-1 Storage	0	0	0	0	0	0	0.0	1.4	1.4
35	Rate T-1 Transportation	0	39	39	0	430,312	430,312	0.0	12.2	12.2
36	Rate T-2 Storage	0	0	0	0	0	0	0.0	7.2	7.2
37	Rate T-2 Transportation	0	25	25	0	4,017,975	4,017,975	0.0	66.9	66.9
38	Rate T-3 Storage	0	0	0	0	0	0	0.0	1.4	1.4
39	Rate T-3 Transportation	0	1	1	0	264,209	264,209	0.0	5.8	5.8
40	Rate M5	5	33	38	2,712	59,105	61,817	0.4	2.1	2.6
41	Rate 25	38	26	64	29,990	62,848	92,838	5.0	2.8	7.8
42	Rate 30	0	0	0	0	0	0	0.0	0.0	0.0
43	**Total Union Rate Zones**	**86**	**439**	**525**	**126,938**	**7,755,045**	**7,881,983**	**23.1**	**186.2**	**209.4**
44	**Total Contract Sales**	**163**	**816**	**979**	**358,763**	**9,959,769**	**10,318,532**	**60.1**	**248.9**	**309.0**
45	**Subtotal**	**3,646,529**	**121,318**	**3,767,846**	**12,898,142**	**13,152,718**	**26,050,861**	**3,695.6**	**563.8**	**4,259.4**
46	**Accounting Adjustments:**									
47	EGI Tax Variance									(13.4)
	EGI Elimination of 2018 Tax Variance									0.0
48	EGI Accounting Policy Change									(14.0)
49	EGD Average Use/ Normalized Average Consumption									(4.6)
50	EGD Dawn Access Cost									2.1
51	EGD Incremental Capital Module									(0.3)
	EGD Elimination of 2018 Earnings Sharing Adjustment									0.0
52	EGD Transactional Services Revenue									12.0
53	EGD LRAM									0.0
54	EGD Federal Carbon Program									0.6
55	EGD Greenhouse Gas Emissions Administration									0.2
56	EGD Reverse 2019 Gas Supply Plan Cost Consequences									(3.9)
57	EGD Elimination of 2019 Gas Supply Plan Cost Consequences reversal									3.9
58	Union Average Use/ Normalized Average Consumption									7.2
59	Union Parkway Obligation Rate Variance									0.0
60	Union Incremental Capital Module									(5.6)
61	Union Capital Pass-through									(1.1)
62	Union LRAM									1.4
63	Union Federal Carbon Program									1.2
64	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.7)
66	Miscellaneous									0.7
67	**Total Utility Revenue**									**4,224.3**

EGI REVENUE FROM REGULATED STORAGE
& TRANSPORTATION OF GAS
2021 ACTUAL

Line No.	Particulars ($000s)	2020 Actual	2021 Actual
	Revenue from Regulated Storage Services:		
1	C1 Off-Peak Storage	1,002	433
2	Supplemental Balancing Services	1,016	640
3	Gas Loans	1	1
4	C1 Short Term Firm Peak Storage	2,715	1,536
5	Short Term Storage and Balancing Services Deferral	907	3,577
6	Rate 325: Transmission, Compression, & Storage	1,988	2,169
7	Less: Elimination of charges between EGD and Union rate zones	(2,000)	(2,226)
8	Total Regulated Storage Revenue Net of Deferral	$ 5,630	$ 6,130
	Revenue from Regulated Transportation Services:		
9	M12 Transportation	206,677	206,637
10	M12-X Transportation	21,335	21,527
11	C1 Long Term Transportation	20,882	19,934
12	Rate 332: Gas Transmission	17,804	18,107
13	C1 Short Term Transportation	5,698	7,226
14	Gross Exchange Revenue	999	1,729
15	Rate 331: Gas Transmission	259	165
16	M13 Local Production	122	157
17	M16 Transportation	1,089	926
18	M17 transportation	109	545
19	S&T:Transportation Carbon Facility Collection	1,931	2,692
20	Other S&T Revenue	1,580	1,440
21	Less: Elimination of charges between EGD and Union rate zones	(136,155)	(138,489)
22	Total Regulated Transportation Revenue Net of Deferral	$ 142,330	$ 142,597

EGI UTILITY OTHER REVENUE AND OTHER INCOME
2021 ACTUALS

Line No.	Particulars	Col. 1 2020 Utility Revenue	Col. 2 2021 Utility Revenue
		($Millions)	($Millions)
1.	Late Payment Penalties	20.8	19.9
2.	Account Opening Charges	9.8	11.1
3.	Other Billing Revenue	3.0	3.2
4.	Customer Billing Revenue	33.6	34.1
5.	Open Bill Revenue	5.4	5.4
6.	Distributor Consolidated Billing and Direct Purchase Administration Charges	2.4	2.3
7.	Mid Market Transactions	1.1	1.2
8.	CNG Rental Revenue	1.8	1.8
9.	Other Operating Revenue	3.4	4.2
10.	Total Other Revenue	47.7	49.1
11.	Other Income	4.5	0.9
12.	Total Other Revenue and Other Income	52.2	50.0

UTILITY O&M

1. This evidence explains the drivers in the Utility Operating and Maintenance (O&M) expense change from 2021 to 2020.

2. The Utility O&M schedule for 2021 preserves the presentation from the 2020 ESM Proceeding (EB-2021-0149) to provide transparency to all expense categories and in particular, segregating Corporate Shared Services (CSS), Demand Side Management (DSM), and Integration-related costs. The Company recognizes that this O&M presentation is useful to inform stakeholders about operating costs, and as such, has maintained the presentation to allow the driver explanations to be comparable between years.

3. Table 1 presents 2021 O&M expenses relative to the prior year. As in 2020, Enbridge Gas provided an appendix reconciling O&M results presented in the format of Table 1 compared to formats previous to 2019. Please refer to Appendix A for the reconciliation for 2021 results and presentation. Given the fact that Enbridge Gas now has three years of historical information presented in the format in Table 1, it is proposed that the reconciliation in Appendix A is no longer required or useful for the remaining deferred rebasing years of 2022 and 2023. Enbridge Gas requests approval to not provide the Appendix A reconciliation going forward after this proceeding.

4. Overall, O&M expenses decreased by $32.3 million primarily due to the non-recurrence of the one-time severance costs for voluntary workforce departures that occurred in 2020. Sustained synergy savings also contributed to the decrease. These decreases were partially offset by increases primarily in CSS, compensation and benefits, outside services, donations and memberships, and vehicle related repairs and maintenance.

Table 1

/U

UTILITY O&M
2021 & 2020 ACTUALS

Line No.	Col. 1 Expense Categories	Col. 2 2020 Actual ($M)	Col. 3 2021 Actual ($M)	Col. 4 $ change	Col. 5 % change
1	Compensation and Benefits	354.7	369.8	15.1	4.3%
2	Employee Related Services and Development	1.5	1.5	(0.0)	-2.0%
3	Materials and Supplies	29.9	32.5	2.6	8.6%
4	Outside Services	220.8	232.1	11.3	5.1%
5	Transportation Related Repairs and Maintenance	6.9	5.7	(1.2)	-17.8%
6	Vehicle Related Repairs and Maintenance	14.3	19.8	5.5	38.1%
7	Rents and Leases	9.9	11.1	1.2	11.7%
8	Telecommunications	0.3	0.2	(0.1)	-35.1%
9	Travel and Entertainment	3.1	3.7	0.6	20.1%
10	Donations and Memberships	3.2	11.3	8.1	258.1%
11	Admin Expenses	(1.6)	(4.1)	(2.5)	162.1%
12	Allocations & Recoveries	(17.8)	(16.5)	1.3	-7.1%
13	Corporate Shared Services (CSS)	187.8	218.1	30.3	16.1%
14	DSM	132.3	132.1	(0.2)	-0.1%
15	Integration-Related Costs	125.2	49.8	(75.4)	-60.2%
16	Miscellaneous Expense	14.7	9.8	(4.9)	-33.4%
17	Capitalization on Non-CSS	(119.5)	(138.2)	(18.7)	15.7%
18	**O&M Subtotal before Eliminations**	**965.7**	**938.7**	**(27.0)**	**-2.8%**
19	Donations	(0.6)	(3.6)	(3.0)	465.1%
20	CDM Program	0.1	0.0	(0.1)	-100.0%
21	ABC T-service Program	(0.2)	(0.3)	(0.1)	76.3%
22	Other Eliminations	0.0	(0.1)	(0.1)	
23	Unregulated Adjustments	(16.6)	(18.5)	(1.9)	11.5%
24	**Total Unregulated/Non-Utility Eliminations**	**(17.3)**	**(22.5)**	**(5.2)**	**30.4%**
25	**Total Net Utility O&M Expense**	**948.5**	**916.2**	**(32.3)**	**-3.4%**

5. With the exclusion of $77.7 million of severance costs in 2020, the remaining integration-related costs (Line 15) increased by $2.4 million as integration initiatives continue to be pursued across all functional areas.

6. CSS costs (Line 13) include business functions such as Legal, Finance, Human Resources and Technology Information Services (TIS) that serve business units across the Enbridge enterprise. CSS costs are primarily comprised of compensation

7. and benefits for CSS employees. Costs are charged to the individual business units based on appropriate cost allocation in relation to the services received.

8. CSS costs were $30.3 million higher than the prior year primarily due to: higher pension and benefits; higher information technology costs driven by cybersecurity investments resulting from government mandates in response to heightened threats to energy companies, deployment and sustainment costs of new technology to support business requirements; higher insurance costs from market conditions brought about by heightened pandemic risk; and lower overhead capitalization of CSS costs (please see Table 2 for more detail).

9. Compensation and benefits (Line 1) increased $15.1M from higher pension and benefits costs. The pension increase was the result of a higher actuarial valuation. Short-term incentive payments (STIP) were higher from stronger performance compared to 2020. Stock-based compensation (SBC) was similarly higher as a result of a higher share price.

10. Outside services (Line 4) increased $11.3M over the prior year primarily due to an increase in integrity spending, higher locates costs due to higher contract rates, higher postage costs from lower e-bill utilization, higher contract costs for call center, back-office billing and collections support, and increases in regulatory consulting costs related to rebasing preparations as well as higher regulatory fees reflecting the volume of proceedings including Integrated Resource Planning (IRP).

11. Donations and memberships (Lines 10 and 19) increased $5.1M (after elimination of donations not deducted for utility purposes) over the prior year due to higher sponsorships relative to 2020 when the pandemic curtailed sponsorship opportunities. Also contributing to the unfavorable variance is the transfer of Union

Gas Low-Income Energy Assistance Program (LEAP) amounts to the Donations and Memberships category in 2021 for tracking and reporting alignment with Enbridge Gas Distribution (EGD) LEAP disbursements. The increase is offset in the Admin Expenses category (Line 11).

12. Vehicle-related repair expenses (Line 6) increased $5.5M in 2021 due to the higher maintenance and repairs needs of an aging fleet of vehicles, as well as from higher fuel prices.

<u>1. 2021 Overhead Capitalization</u>

13. The following section describes total overhead capitalization for both CSS (included in Line 13) and non-CSS cost categories (Line 17).

14. Overhead capitalization applies to all expense categories except integration-related costs, which are fully expensed. Total combined overhead capitalization was $10.4M more than the prior year (Table 2).

15. Non-CSS overhead capitalization increased by $18.7M driven by the increases in O&M expenses noted in the previous section.

16. CSS overhead capitalization decreased by $8.3M from the prior year primarily due to lower direct labour engaged in 2021 capital activity. With the completion of the labor-intensive Customer Information System (CIS) capital Information Technology (IT) project in 2020, direct labour burdens were lower in 2021 by comparison. While CSS costs increased, the increase was primarily due to higher pension and benefits, which flow to capital through burdening of direct and indirect labour.

Table 2

Total Overhead Capitalization Impact on O&M

	2020 Actual ($M)	2021 Actual ($M)	Variance ($M)
CSS-related Capitalization	(105.0)	(96.7)	8.3
Capitalization on Non-CSS	(119.5)	(138.2)	(18.7)
	(224.5)	(234.9)	(10.4)

17. While reconciliation tables were provided in the 2020 ESM application (Appendices, EB-2021-0149) to aid in the understanding and adoption of the new schedule, as well as to provide visibility to Corporate Allocations and Recoveries as agreed to in the 2019 ESM Settlement Proposal, inbound allocations and outbound recoveries are no longer relevant for 2021 as all CSS costs are inbound to Enbridge Gas. Affiliates are similarly allocated their charges directly through Enbridge Inc. and not through Enbridge Gas. Table 3 summarizes the Total Corporate allocation, the CSS capitalization applied, and Total Net CSS. Variance explanations are as noted in previous sections.

Table 3

Corporate Allocations and CSS

	2020	2021	2020-2021 Variance
Total Gross CSS	292.8	314.8	22.0
Less: Capitalization of CSS	(105.0)	(96.7)	8.3
Net CSS	187.8	218.1	30.3

Appendix A

/U

RECONCILIATION OF UTILITY O&M SCHEDULE
2020 & 2021 Results

Col. 1		Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
		2020 ACTUAL				2021 ACTUAL				2020-2021	2020-2021
Line No.	Expense Categories ($M)	2020 As filed[1]	Central Functions Costs	DSM & Integration Costs	**2020 Revised**	2021 Previous Format	Central Functions Costs	DSM & Integration Costs	**2021 Revised**	$ change	% change
1	Compensation and Benefits	572.2	(108.0)	(109.5)	354.7	514.2	(112.8)	(31.6)	369.8	15.2	4.3%
2	Employee Related Services and Development	6.5	(4.8)	(0.2)	1.5	5.1	(3.1)	(0.5)	1.5	(0.0)	-2.0%
3	Materials and Supplies	92.1	(5.3)	(56.9)	29.9	97.7	(7.9)	(57.3)	32.5	2.6	8.6%
4	Outside Services	341.3	(36.6)	(83.9)	220.8	364.0	(39.3)	(92.6)	232.1	11.3	5.1%
5	Transportation Related Repairs and Maintenance	9.8	(2.9)	(0.0)	6.9	9.2	(3.5)	(0.0)	5.7	(1.2)	-17.8%
6	Vehicle Related Repairs and Maintenance	14.4	(0.0)	(0.0)	14.3	19.9	(0.0)	(0.1)	19.8	5.5	38.1%
7	Rents and Leases	12.4	(2.5)	(0.0)	9.9	12.5	(1.4)	-	11.1	1.2	11.7%
8	Telecommunications	3.8	(3.5)	(0.0)	0.3	2.5	(2.3)		0.2	(0.1)	-35.1%
9	Travel and Entertainment	4.3	(0.9)	(0.4)	3.1	4.1	(0.3)	(0.1)	3.7	0.6	20.1%
10	Donations and Memberships	4.3	(0.2)	(0.9)	3.2	12.4	(0.3)	(0.7)	11.3	8.1	258.1%
11	Admin Expenses	0.9	0.8	(3.3)	(1.6)	(4.7)	(1.2)	1.7	(4.1)	(2.5)	162.1%
12	Allocations & Recoveries	113.4	(128.8)	(2.3)	(17.8)	126.2	(142.1)	(0.7)	(16.5)	1.3	-7.1%
13	Corporate Shared Services (CSS)		187.8		187.8	-	218.1		218.1	30.3	16.1%
14	DSM			132.3	132.3	-		132.1	132.1	(0.2)	-0.1%
15	Integration-Related Costs			125.2	125.2	-		49.8	49.8	(75.4)	-60.2%
16	Miscellaneous O&M Expense	14.7			14.7	9.8			9.8	(4.9)	-33.4%
17	Capitalization on non-CSS	(224.3)	104.9		(119.5)	(234.3)	96.0		(138.2)	(18.7)	15.7%
18	O&M Subtotal before Eliminations	965.7	(0.0)	(0.0)	965.7	938.7	(0.0)	0.0	938.7	(27.0)	-2.8%
19	Donations	(0.6)			(0.6)	(3.6)			(3.6)	(3.0)	465.1%
20	CDM Program	0.1			0.1	0.0			0.0	(0.1)	-100.0%
21	ABC T-service Program	(0.2)			(0.2)	(0.3)			(0.3)	(0.1)	76.3%
22	Other Eliminations	0.0			0.0	(0.1)			(0.1)	(0.1)	-
23	Unregulated Adjustments	(16.6)			(16.6)	(18.5)			(18.5)	(1.9)	11.5%
24	Total Unregulated/Non-Utility Eliminations	(17.3)			(17.3)	(22.5)			(22.5)	(5.2)	30.4%
25	Total Net Utility O&M Expense	948.5			948.5	916.2			916.2	(32.3)	-3.4%

UTILITY CAPITAL EXPENDITURES

1. The purpose of this evidence is to provide information on Enbridge Gas' 2021 utility capital expenditures within the EGD and Union rate zones.

Table 1
Summary of Capital Expenditures 2021 Actual
($millions)

	Col 1	Col 2	Col 3
	EGD	**UG**	**TOTAL EGI**
Distribution Plant	457.9	465.4	923.2
Transmission Plant	-	128.6	128.6
General & Other Plant	113.0	74.3	187.3
Underground Storage Plant	59.5	12.2	71.7
	630.4	**680.4**	**1,310.8**

2. The dollars presented are annual capital expenditures and are comparable to the presentation in the Asset Management Plan. Capital expenditures in ICM applications are presented on an in-service basis.

3. Table 2 below shows the regulated expenditures by Asset Class for each of the legacy rate zones. Further commentary regarding the year over year changes in capital expenditures are described by Asset Class in the narrative following Table 2.

Table 2
EGD Rate Zone by Asset Class
($millions)

	Asset Class	2020	2021	Variance
A	Compression Stations	9.2	26.8	17.6
B	Customer Connections	117.5	172.0	54.4
C	Distribution Pipe	58.5	151.0	92.6
D	Distribution Stations	33.7	43.4	9.8
E	Fleet & Equipment	11.3	15.3	4.0
F	Growth - Distribution System Reinforcement	8.4	13.4	5.0
G	Real Estate & Workplace Services	22.2	40.2	18.0
H	Technology Information Services (TIS)	13.8	12.7	(1.1)
I	Transmission Pipe and Underground Storage	12.7	32.7	20.0
J	Utilization	31.3	34.8	3.5
K	EA Fixed Overhead	15.7	19.5	3.8
L	Capitalized Overheads	131.9	-	(131.9)
M	Integration Capital	19.2	44.8	25.6
N	Community Expansion	20.2	13.5	(6.7)
O	Other	1.6	10.1	8.6
	Total Capital Expenditures	**507.2**	**630.4**	**123.2**

Table 2
UG Rate Zone by Asset Class
($millions)

	Asset Class	2020	2021	Variance
A	Compression Stations	17.3	15.5	(1.8)
B	Customer Connections	61.1	88.7	27.6
C	Distribution Pipe	134.3	296.1	161.8
D	Distribution Stations	27.7	47.8	20.1
E	Fleet & Equipment	8.9	11.4	2.5
F	Growth - Distribution System Reinforcement	61.6	35.1	(26.5)
G	Real Estate & Workplace Services	16.1	30.3	14.2
H	Technology Information Services (TIS)	9.0	10.1	1.2
I	Transmission Pipe and Underground Storage	20.8	46.8	26.0
J	Utilization	31.6	45.9	14.3
K	EA Fixed Overhead	3.8	5.9	2.2
L	Capitalized Overheads	90.3	-	(90.3)
M	Integration Capital	19.3	42.7	23.4
N	Community Expansion	0.7	3.8	3.1
O	Other	(2.5)	0.3	2.8
	Total Capital Expenditures	**500.0**	**680.4**	**180.4**

1. Descriptions of Asset Classes and Year over Year Variances

4. Effective January 2021, EGI is allocating capitalized overheads to projects based on the total pool of overheads and the total direct capital spend by rate zone. As a result, capitalized overheads are being reflected within the asset classes and will no longer shown as a separate asset class. This is consistent with the presentation of overheads in the Asset Management Plan and ICM applications (as of 2021).

A. Compression Stations

EGI (Union rate zone) uses compressors to move natural gas throughout the natural gas transmission system by compressing natural gas into transmission pipelines designed for high pressure and flow. Compressors are also used for both rate zones to move gas in and out of underground storage reservoirs by providing a significant pressure increase at the expense of flow.

Dehydration facilities are also included in the compression asset category. Dehydration facilities remove moisture from natural gas to ensure that the natural gas entering the transmission system meets the contractual standard of moisture content, and to avoid operational problems related to high moisture content. EGI operates one liquified natural gas (LNG) facility, the LNG facility serves to provide reserve capacity and balance operational loads during peak periods.

The EGD rate zone increased due to the pacing of large growth projects in 2021 including: Ph 1 ($14.0M) and Ph 2 ($2.2M) of the Corunna (SCOR) Meter Area Upgrade.

The Union rate zone had an overall decrease due to the timing of land purchases adjacent to facilities and the variability in the cost/timing of unplanned compressor failures that require capital treatment, countered by an increase in improvement projects.

The inclusion of overheads is a $7.9M increase compared to 2020 spend.

B. Customer Connections

This asset class includes:

- The addition of new customers based on new housing or business starts;
- Customers converting to natural gas from another fuel source;
- Equipment and service upgrades to accommodate load growth of existing customers; and
- General customer growth costs include materials and installation of mains and services to attach new customers as well as the costs associated with the meter and regulator installation at the customers site.

In the EGD rate zone there was an increase in customers connected in 2021 compared to 2020. In both rate zones, the cost of labour and materials also increased due to shortages, inflation rates and unfavourable currency exchange rates.

The inclusion of overheads is a $49.0M increase compared to 2020 spend.

C. Distribution Pipe

This asset class includes the maintenance, replacement, and renewal of pipelines and piping components (such as valves and fittings) used to transport natural gas within the distribution system or to end-use customers. It includes steel and plastic pipe, as well as services to customers.

In the EGD rate, the increase was largely driven by the timing of vintage steel investments, the significant investment for NPS 20 Lake Shore Replacement (Cherry to Bathurst) ($20.9M), the return of the AMP fitting and other programs following curtailment in 2020 for COVID-19.

For the Union rate zone, the increase was driven by large ICM projects including the London Lines Replacement ($73.4M) and the West Portion of the Windsor Lines ($34.2M).

Both rate zones saw increases in integrity retrofits and digs and relocations compared to 2020. Both rate zones saw cost variances driven by the deferral of work as a result of inflation and COVID-19 impacts to materials, accessibility and resources.

The inclusion of overheads is a $83.2M increase compared to 2020 spend.

D. Distribution Stations

These assets are typically above grade facilities designed to reduce the operating pressure of natural gas pipeline systems through pressure control and over pressure protection. These facilities are used to transmit and/or distribute natural gas to reduced operating pressure pipeline systems which supply natural gas to cities and towns.

The EGD rate zone variance is due to minor shifts in investment cost and timing.

In the Union rate zone, the overall increase was driven by an increase in the Station Rebuilds & B and C Stations program and increased Integrity Assessments to establish the condition of the station components and adjust project scopes to address the integrity findings. This was partially offset by a decrease in both CNG stations and Gate, Feeder and A Stations due to Dawn CNG ($1.4M), Hamilton Gate 1 Rebuild ($9.3M) and Oxford Gate Station ($7.0M) requiring capital spend in 2020.

The inclusion of overheads is a $17.1M increase compared to 2020 spend.

E. Fleet & Equipment

The Fleet, Equipment and Tools asset class includes the vehicles, trailers, heavy equipment and tools owned by EGI to support its business needs.

For the EGD rate zone, spend was pulled forward into 2021 for the TDW ProStopp tool ($4.1M) which improves safety for workers during construction activities. This was countered by a decrease in vehicle purchases due to delays in supply chain.

The Union Gas rate zones did not have significant variances from 2020.

The inclusion of overheads is a $5.0M increase compared to 2020 spend.

F. Growth – Distribution System Reinforcement

The Growth asset class includes reinforcements driven by customer and load growth.

For the EGD rate zone, there was an overall increase due to investment cost and timing.

For the Union rate zones, there was an overall decrease due to the larger Growth projects executed in 2020, including Kingsville Transmission ($9.8M) and Owen Sound Reinforcement Ph 4 ($56.4M). In 2021, the significant Growth projects were Byron Transmission Station ($14.0M) and Staples Reinforcement ($5.7M).

The inclusion of overheads is a $9.0M increase compared to 2020 spend.

G. Real Estate and Workplace Services

The Real Estate and Workplace Services (REWS) asset class includes properties (buildings and land) and furnishings.

There is a base spend for each rate zone that supports building repairs and acquisition of furnishings. Variances are driven by the specific land purchases and building renovations that occur in a given year. Land acquisitions are driven by market availability and are aligned with the long-term strategies described in the Asset Management Plan.

In 2021, there was a significant investment in lands to execute the SMOC/Coventry Facility Consolidation ($15.7M) and the Kennedy Road Expansion Project ($2.6M) in the EGD rate zone. For the Union rate zone, the significant investment was the new Belleville Property Construction ($7.5M). The significant real estate investments vary year over year due to market availability and project scope variation to meet business facility requirements.

Significant renovations at for the VPC Annex/Metershop Area Renovations ($9.1M) in the EGD rate zone and the 50 Keil Drive Renovations ($6.1M 2nd Floor & $5.1M 3rd Floor) in the Union rate zone occurred in 2021.

The inclusion of overheads is a $13.2M increase compared to 2020 spend.

H. Technology Information Services

The Technology Information Services (TIS) asset class includes:

- General Hardware (Laptops/Desktops and Desktop sustainment equipment, networks, servers and security);
- Specialized Hardware (to support specific business needs such as meter

reading equipment, call center network devices);

- Software assets consisting of packaged applications, developed applications, and application infrastructure software; and
- Communications assets including mobile phones and field devices (such as GPS devices, push-to-talk radios, leak survey field technology, and truck modems).

For the EGD rate zone, there was a decrease in the TIS infrastructure compared to 2020 due to higher spends on Desktop Replacement ($2.9M) and the Microsoft Enterprise Agreement ($1.8M) in 2020.

For the UG rate zone, there was no significant variance.

The inclusion of overheads is a $4.3M increase compared to 2020 spend.

I. Transmission Pipe and Underground Storage

This asset class includes the pipelines that form the backbone of the gas transmission system as well as the underground storage reservoirs in St. Clair Township near Sarnia, Crowland Township in Welland, and in Chatham-Kent.

Increases in the EGD rate zone were primarily related to the timing of land purchases at facilities, an increase in MOP verification and remediation replacement projects, the timing of the Wilksport (LWLK) Well Debris Filter improvement project ($2.5M) and an increase in retrofits & integrity digs for the Integrity Management Program.

In the UG rate zone, the Sarnia Expansion Growth Projects ($10.8M Novacor Station & 21.1M NPS 20 Dow to Bluewater [LTC: EB-2019-0218]) were the major driver to the increase. The 2021 replacement spend was lower than 2020, where the execution of the 2020 Trafalgar projects ($12.8M) took place.

The inclusion of overheads is a $14.8M increase compared to 2020 spend.

J. Utilization

The utilization asset class includes measurement & regulation systems at customer premises, below ground and internal piping systems after the meter, and customer-owned systems[1].

The EGD rate zone saw reductions in planned meter exchanges as a result of COVID-19 and its impact on supply chain and contractor resources.

Meter purchases in Union rate zone were higher in 2021 compared to 2020 as meters from 2020 were advanced and executed in 2019.

The inclusion of overheads is a $15.1M increase compared to 2020 spend.

K. EA Fixed Overheads

The EA fixed overhead asset class includes cost for Alliance partner overheads and district contractor pre-work costs. The increase is due to additional planning work related to the Vintage Steel Program in the EGD rate zone and timing of payments for both EGD and Union rate zones.

[1] For customer owned systems that are downstream of the meter, the asset class is accountable for inspection at the time of initial installation and after re-introduction of gas. Maintenance and remediation of these assets are the responsibility of the customer.

L. Capitalized Overheads

As set out above, effective January 2021, EGI is allocating capitalized overheads to projects based on the total pool of overheads and the total direct capital spend by rate zone. As a result, capitalized overheads are being reflected within the asset classes and will no longer shown as a separate asset class. This is consistent with the presentation of overheads in the Asset Management Plan and ICM applications (as of 2021).

Total combined overhead capitalization increased by $10M. The overhead increases are explained in B-3-1.

M. Integration Capital

Integration capital includes expenditures required to integrate the two legacy companies. EGI continues to evaluate projects to determine if they meet the criteria of integration capital: a one time incremental cost related to the amalgamation of the legacy utilities. Projects can be newly identified to address integration needs, or they may be driven by a need to replace an asset due to obsolescence. In either case, the project is classified as integration as it is driving a harmonized solution that adds value to the integrated utility. It is important to note that the work being addressed through some integration projects would have been required for either or both rate zones in the absence of amalgamation (because of factors such as obsolescence or growth), but the projects are nonetheless included as integration capital because the project is done for the amalgamated utility. An example of work related to integration expenditures would be the integration of the customer billing systems. These expenditures are excluded when calculating the thresholds for ICM capital.

The increase in the EGD rate zone is due to the purchase of land for the new GTA West site and the Integrated Utility Asset & Work Management project.

The increase in the UG rate zone is due to the completion of the CIS Integration project and continued work on the Cost of Gas project.

The inclusion of overheads is a $16.4M increase compared to 2020 spend.

N. Community Expansion

Community expansion provides natural gas services to communities not currently using natural gas. In response to the Ontario Energy Board's (OEB) initiative to address the Government of Ontario's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas, EGI has filed proposals with the OEB designed to facilitate enhanced access to natural gas for non-served rural, remote and First Nation communities, and businesses in Ontario.

In the EGD rate zone, the decrease in spend is primarily related to lower spend on the Fenelon Falls and Scugog Island projects due to construction completion, offset by the start of design work for the Community Expansion Phase 2 projects.

In the Union rate zone, the increase in spend is related to construction with the Northshore & Peninsula project.

5. Table 3 below shows the Asset Classes with storage spend for each rate zone and the allocation of costs between the regulated and unregulated segments of EGI's storage operations. Both the EGD and Union rate zones have OEB approved policies and methodologies for unregulated storage allocations. Allocations are

maintained at the individual asset level and updated annually to reflect additions and retirements to the assets. The allocations are applied to storage based capital projects in order to separate the regulated and unregulated costs. Regulated projects include indirect overhead allocations.

Table 3
EGD Rate Zone Storage by Asset Class 2021 Actual
($millions)

	Asset Class	Regulated	Unregulated
A	Compression Stations	26.8	1.3
B	Transmission Pipe and Underground Storage	32.7	13.0
	Total Capital Expenditures	**59.5**	**14.3**

6. Compression Stations – significant regulated projects Corunna (SCOR) Meter Area Upgrade Phase 1 ($14.0M), Corunna (SCOR) Meter Area Upgrade Phase 2 ($2.2M), SCOR:100MODHdr Valves-Replace ($1.4M) and SCOR:60004 iBalance-Upgrade ($1.3M).

7. Transmission Pipe and Underground Storage – significant projects related to EGD's regulated assets include Wilkesport MOP Remediation ($6.2M), NPS16 LAD-WLK Interconnect MOP ($4.1M), LLAD:, strategic land purchases at 2 locations around the underground storage facilities ($5M), Wilksport (LWLK) Well Debris Filter ($2.5M), NPS 16 Coveny Trans. Retrofit ($2.3M) and NPS 16 COV Gathering Retrofit ($2.2M). Significant unreglated projects include Pipeline and Meter Station – Upgrade ($6.2M). This is part of the 2020/2021 Storage Enhancement project (EB-2020-0074) which will increase the maximum operating pressure of the Black Creek, Coveny and Wilkesport pools. The Storage Enhancement projects are being executed in 2 phases in order to meet the growing market demand for incremental storage space.

Table 3
UG Rate Zone Storage by Asset Class
($millions)

	Asset Class	Regulated	Unregulated
A	Compression Stations	15.5	1.8
B	Transmission Pipe and Underground Storage	46.8	9.2
	Total Capital Expenditures	**62.3**	**11.0**

8. Compression Stations – significant projects related to UG's regulated assets include strategic land purchases at 3 locations around the underground storage facilities ($5.2M) and the Sandwich Gas Generator Overhaul ($0.7M). Transmission Pipe and Underground Storage – significant projects related to UG's regulated assets include Sarnia Expansion – Bluewater Energy Park ($21M), Sarnia Expansion – Novacor Stn ($10.8M), NPS 34 Trafalgar Digs ($2.2M) and Panhandle Line Depth of Cover Mitigation ($2M). The INTE: 156 Storage and Pool Loop: Permanent L R Facilities ($3.4M) project has both a regulated and unregulated component due to the allocation applied to the storage pool assets. The SE 21/22 LCOR:Payne Tie-In ($2.4M) is an unregulated project and is part of the 2nd phase of the Storage Enhancement project (EB-2021-0079) described in paragraph 7 above.

ENBRIDGE GAS
SUMMARY OF CAPITAL COST ALLOWANCE (CCA)

Line No.	Class	Particulars ($000s)	Col. 1 UCC at Prior Year Filing EB-2021-0149 (a)	Col. 2 True-up from Filing to Tax Return (b)	Col. 3 UCC At Beginning of Year (c)	Col. 4 Total Additions (d)	Col. 5 Total Additions Qualifying for Accel. CCA (e)	Col. 6 Less: Lessor of Cost or Proceeds (f)	Col. 7 Eligible CCA Additions (g)	Col 8 Depreciable UCC Balance (h)	Col. 9 Rate (%) (i)	Col. 10 CCA FY2021 (j)	Col. 11 Ending UCC (k)
1.	1	Buildings, structures and improvements, services, meters, mains	2,298,694.5	-	2,298,694.5	-	-	-	-	2,298,694.5	4%	91,947.8	2,206,746.7
2.	1	Non-residential building acquired after March 19, 2007	118,836.9	(386.3)	118,450.6	31,673.9	31,047.5	-	46,884.5	165,335.0	6%	9,920.1	140,204.4
3.	2	Mains acquired before 1988	162,237.1	(14.9)	162,222.2	-	-	-	-	162,222.2	6%	9,733.3	152,488.9
4.	3	Buildings acquired before 1988	2,996.9	-	2,996.9	-	-	-	-	2,996.9	5%	149.8	2,847.0
5.	6	Other buildings	80.3	(2.0)	78.3	-	-	-	-	78.3	10%	7.8	70.5
6.	7	Compression equipment acquired after February 22, 2005	490,024.8	(9.2)	490,015.5	5,851.4	5,789.8	-	8,715.5	498,731.0	15%	74,809.7	421,057.3
7.	8	Compression assets, office furniture, equipment	191,576.3	(190.8)	191,385.5	17,583.7	17,583.7	-	26,375.5	217,761.0	20%	43,552.2	165,417.0
8.	10	Transportation, computer equipment	28,978.1	42.8	29,020.9	8,412.0	8,412.0	(84.2)	12,575.9	41,512.6	30%	12,453.8	24,894.9
9.	12	Computer software, small tools	1,521.5	(1,521.5)	-	60,466.4	57,423.4	-	58,944.9	58,944.9	100%	58,944.9	1,521.5
10.	13	Leasehold improvements	673.9	(110.1)	563.8	-	-	-	-	563.8	0%	212.1	351.7
11.	14.1	Intangibles	10,574.1	(4.9)	10,569.1	2,802.8	2,704.6	-	4,106.0	14,675.1	5%	733.8	12,638.2
12.	14.1	Intangibles (pre 2017)	46,798.6	-	46,798.6	-	-	-	-	46,798.6	7%	3,275.9	43,522.7
13.	17	Roads, sidewalk, parking lot or storage areas	502.6	-	502.6	-	-	-	-	502.6	8%	40.2	462.4
14.	38	Heavy work equipment	10,956.3	(28.1)	10,928.2	2,587.3	2,587.3	-	3,880.9	14,809.1	30%	4,442.7	9,072.7
15.	41	Storage assets	51,577.1	3,707.2	55,284.2	56,745.2	52,156.7	-	80,529.3	135,813.6	25%	33,953.4	78,076.1
16.	45	Computers - Hardware acquired after March 22, 2004	6.3	-	6.3	-	-	-	-	6.3	45%	2.8	3.4
17.	49	Transmission pipeline additions acquired after February 23, 2005	744,028.8	8,131.1	752,159.9	75,728.0	75,728.0	-	113,592.0	865,751.9	8%	69,260.2	758,627.8
18.	50	Computers hardware acquired after March 18, 2007	14,927.1	315.9	15,243.1	22,927.3	16,965.5	-	28,429.2	43,672.3	55%	24,019.7	14,150.7
19.	51	Distribution pipelines acquired after March 18, 2007	5,303,987.9	(23,723.9)	5,280,264.0	836,580.8	834,194.2	-	1,252,484.7	6,532,748.7	6%	391,964.9	5,724,879.9
20.		Total	9,478,979.1	(13,794.8)	9,465,184.3	1,121,359.0	1,104,592.6	(84.2)	1,636,518.3	11,101,618.5		829,425.1	9,757,034.0

ACCOUNTS NOT BEING REQUESTED FOR CLEARANCE

1. The Company is not seeking clearance of the following accounts in this proceeding. For the following accounts, Enbridge Gas will carry the balances forward and seek clearance in appropriate future proceedings:
    - Accounting Policy Changes Deferral Account - EGI
    - Tax Variance Deferral Account – Integration-related Balances - EGI
    - Impacts Arising from the COVID-19 Emergency Deferral Account - EGI
    - Incremental Capital Module Deferral Account - EGD Rate Zone
    - Incremental Capital Module Deferral Account - Union Rate Zones

2. The following accounts of Enbridge Gas have zero balances and are therefore not requested for clearance:
    - IRP Capital Costs Deferral Account - EGI
    - Earnings Sharing Mechanism Deferral Account - EGI
    - Expansion of Natural Gas Distribution Systems Variance Account - EGI

ENBRIDGE GAS – ACCOUNTING POLICY CHANGES DEFERRAL ACCOUNT (APCDA) (No. 179-381)

1. On August 30, 2018 the Ontario Energy Board (OEB) issued its Decision and Order for the amalgamation and rate setting mechanism (the MAADs Decision) approving the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union) and the rate-setting framework[1]. In its Decision, the OEB established a deferral account to record the impact of any accounting changes required as a result of amalgamation that affect the revenue requirement.[2] The OEB approved wording of the accounting order for the Accounting Policy Changes Deferral Account (APCDA) effective January 1, 2019 in its Decision and Order on Enbridge Gas' 2019 Rates application[3].

2. As per the EB-2020-0134 Decision on Settlement Proposal, as part of the settlement proposal, parties agreed to defer the review, allocation and disposition of all balances in the APCDA until the end of Enbridge Gas's deferred rebasing term (2023). Parties noted that they required more information regarding the treatment of the balances and the extent of rate harmonization post-rebasing before approval of the balances and the disposition methodology can be considered[4].

3. The Company continues to track the annual revenue requirement impact of accounting policy changes made as of the amalgamation date, January 1, 2019, as well as any further accounting policy changes adopted since that time. The cumulative balance of the APCDA as of December 31, 2021 is a receivable of $139.028 million, driven by the revenue requirement impact of five accounting

[1] EB-2017-0306/0307, MAAD's Decision and Order dated August 30, 2018; The Decision and Order was later amended by the OEB on September 17, 2018 with no material changes.
[2] EB-2017-0306/0307, MAAD's Decision and Order dated August 30, 2018, page 47.
[3] EB-2018-0305, 2019 Rates Final Rate Order dated October 24, 2019, Appendix I, page 7.
[4] EB-2020-0134, Decision on Setlement Proposal dated January 25, 2021, pages 4-5.

changes arising from (and since) amalgamation, which are detailed in the table below. The table categorizes each of the accounting policy changes, provides the cumulative opening balance as of the beginning of the period, details the current period revenue requirement impact being added to the cumulative balance, and finally provides the ending cumulative balance as of the end of the current period. The details of each item within the table below are described further in the remaining evidence presented.

	Revenue Requirement $millions						
	Capitalization vs Expense	Interest During Construction	Depreciation Expense	Overhead Capitalization	**Subtotal**	Pension Expense	Total
Balance at January 1, 2021	(0.786)	0.887	(10.214)	(6.427)	**(16.539)**	181.465	164.926
Impact to 2021 revenue requirement:							
Expense	(3.652)	0.076	(4.882)	(4.735)	**(13.193)**	(12.033)	(25.226)
Cost of capital	0.125	0.112	0.687	0.668	**1.592**	-	1.592
Income tax	(0.097)	0.274	(1.647)	(0.794)	**(2.264)**	-	(2.264)
Total	(3.624)	0.462	(5.842)	(4.861)	**(13.865)**	(12.033)	(25.898)
Balance at December 31, 2021	(4.410)	1.349	(16.056)	(11.288)	**(30.404)**	169.432	139.028

4. Please refer to Exhibit C, Tab 1, Schedule 2 for the detailed 2021 revenue requirement calculation of the items presented above.

1. Capitalization vs Expense

5. Capitalization policies differed between EGD and Union with respect to whether the following items were capitalized or expensed as incurred:

	Union Policy	EGD Policy	EGI Policy
• Verification of Maximum Operating Pressure Program ("MOP"); • Customer Assets Programs (Low Pressure Delivery Meter Set and Farm Tap Programs); • Distribution Integrity Technology; • Distribution Records Management Program; and,	Expensed as incurred	Capitalized	Expensed as incurred
• Integrity Digs resulting from integrity inspections	Expensed as incurred	Capitalized	Capitalize

6. Upon amalgamation, it was necessary for Enbridge Gas to align its capitalization policies where differences existed between legacy EGD and legacy Union. The policy alignment resulted in a net impact in 2021 between UGL and EGD Rate Zones of:
   - Lower O&M expense of approximately $3.638 million, offset by higher capitalization; and,
   - Gross revenue requirement decrease, or sufficiency of $3.624 million.

2. Interest During Construction

7. Interest During Construction (IDC) is a cost of constructing an asset which is included in the cost of property plant and equipment capitalized.[5] IDC is recovered in rates through depreciation expense, along with a return on rate base over the life of

[5] ASC 835-20-05-1.

the asset. Both Union and EGD capitalized IDC in accordance with US GAAP, however, IDC calculation was different in the legacy utilities, as seen below.

	Union Policy	EGD Policy	EGI Policy
Threshold	IDC is only calculated on projects with capital spend of $1 million or greater, and that have a duration of greater than 12 months	No threshold – applied to all capital projects regardless of size and duration	No Threshold – applied to all capital projects regardless of size and duration
Rate	OEB prescribed interest rate for CWIP	Weighted average cost of debt (WACD)	OEB prescribed interest rate for CWIP

8. Upon amalgamation, it was necessary for Enbridge Gas to align its accounting treatment of IDC. The policy alignment resulted in the following for 2021:
    - Total 2021 net gross revenue requirement increase, or deficiency of $0.711 million.
    - A 2020 true-up to the EGD IDC WACD rate in 2021 resulted in a revenue requirement decrease, or sufficiency of $0.249 million.

3. Depreciation Expense

9. Depreciation rates for Union and EGD are based on depreciation studies that were approved by the OEB in prior proceedings. The respective depreciation studies for each EGD and Union Rate Zones continue to be used by Enbridge Gas.

10. Upon amalgamation, it was necessary for Enbridge Gas to align the depreciation policies of legacy EGD and legacy Union Gas with respect to how depreciation on assets is calculated.

Union Policy	EGD Policy	EGI Policy
Half year of depreciation in the first and last year of service, regardless of month the asset went into service	Begin depreciation the month after the asset goes into service, and stops the month after retirement	Begin depreciation the month after the asset goes into service, and stops the month after retirement

11. Since many projects go into service late in the year, the EGD/Enbridge Gas policy would typically result in a lower first year depreciation expense than following the Union policy.

12. The policy alignment resulted in an impact in 2021 specific only to the UGL Rate Zone of:
    - A decrease in depreciation expense of approximately $4.882 million; and,
    - A gross revenue requirement decrease, or sufficiency of $5.842 million.

4. Overhead Capitalization

13. Following amalgamation, the Company sought to harmonize its overhead capitalization methodology and retained Ernst and Young (EY) to carry out the study. EY's assessment was informed by historical legacy approaches, the amalgamated structure, US GAAP, the OEB's Uniform System of Accounts, and Enbridge's Enterprise Capitalization Policy. Recommendations of the study were implemented in January 2020. The study grouped costs into Operations Costs, Business Costs, Support Costs, and Pension and Benefits, each with their own capitalization treatment to more directly link with causal determinants of cost.

14. Prior to this harmonization, capitalized overheads in the legacy EGD approach were determined by the application of Departmental Labour Costs (DLC) rates and Administrative & General (A&G) rates to support costs for capital work in field operations and business support operations, as well as administrative functions that

support the overall business. In legacy UG, annual updates were carried out for support groups where capitalization rates were derived from time spent on capital activity.

15. The APCDA isolates the impact of the overhead capitalization policy change. The calculation takes the annual O&M spend with the new harmonized rates and subtracts from it O&M spend using the legacy rates to determine the APCDA impact. The policy change results in a decrease in O&M and offsetting increase in capitalized overheads, with the revenue requirement impact recorded in the APCDA. The net impact in 2021 between UGL and EGD Rate Zones was:
    - Lower net OM&A expenses of $5.4 million (offset by higher capitalization of overheads); and,
    - A gross revenue requirement decrease, or sufficiency of $4.861 million

<u>5. Pension Expense – Unamortized Actuarial Gains/Losses and Prior Service Costs</u>

16. Prior to December 31, 2018, Union recorded actuarial gains/losses and past service costs (Actuarial Losses) in Accumulated Other Comprehensive Income (AOCI) and amortized the balance over the expected average remaining service life (EARSL) of employees in accordance with ASC 715-30-35-24. This amortization expense was part of pension cost that was recognized annually and included in the forecast that underpinned rates. As a result of the Enbridge Inc. (EI) and Spectra merger (the Merger) on February 27, 2017, EI recorded the acquisition of Union through a purchase price allocation (PPA) in accordance with ASC 805. As a result, Union's pension assets were adjusted on EI's books to fair value and the unamortized Actuarial Losses of $250 million were reclassified from AOCI to Goodwill. These

adjustments were not required to be pushed down[6] and were not pushed down to the Union stand alone financial statements. Therefore, this adjustment did not impact Union financial statements or accounting at the time of the merger.

17. Approximately $39 million of Actuarial Losses were amortized between February 27, 2017 and December 31, 2018, resulting in a balance of $211 million remaining in Union's AOCI at amalgamation (the Amalgamation) (January 1, 2019).

18. Upon amalgamation, US GAAP required the PPA recorded by Enbridge Inc. related to Union to be pushed down into the combined financial statements of Enbridge Gas.[7] This resulted in the remaining unamortized Actuarial Losses on Union's balance sheet to be reclassified from AOCI to Goodwill.

19. Although this appears to be a balance sheet reclassification only, the adjustment would have a significant impact on Enbridge Gas if not for regulatory accounting. AOCI is amortized as an annual expense whereas Goodwill is not. As such, this treatment would result in stranding the balance in Goodwill that would never be expensed. This is an accounting change that occurred only because of the amalgamation. Otherwise, Union would have continued to amortize Actuarial Losses as pension expense, just as it had done in the past.

[6] *Pushdown accounting* refers to establishing a new basis of accounting in the separate financial statements of the acquired entity (or acquiree) after it is acquired. The acquisition adjustments recorded by the acquirer in a business combination under ASC Topic 805 are pushed down to the acquiree's separate financial statements.
[7] In accordance with *ASC 805-50-30-5*:*"When accounting for a transfer of assets or exchange of shares between entities under common control, the entity that receives the net assets or the equity interests shall initially measure the recognized assets and liabilities transferred at their carrying amounts in the accounts of the transferring entity at the date of transfer. If the carrying amounts of the assets and liabilities transferred differ from the historical cost of the parent of the entities under common control, for example, because pushdown accounting had not been applied, then the financial statements of the receiving entity shall reflect the transferred assets and liabilities at the historical cost of the parent of the entities under common control."*

20. The change in accounting policy has not altered the fact that Union has incurred the Actuarial Losses and should recover these costs over time, as is currently approved by the OEB. As noted previously, the balances represent the accumulation of Actuarial Losses incurred in relation to the pension assets that Enbridge Gas needs to continue to fund through cash contributions to the pension plans. Enbridge Gas's funding requirements do not change simply because the accounting treatment has changed. Therefore, continued recovery in rates through the deferred rebasing period is appropriate and is consistent with the OEB's approved approach for utilities. As noted in the *"Report of the Ontario Energy Board – Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs – EB-2015-0040,"* accrual based accounting for pensions under ASC 715 would result in a match to actual cash contributions by the end of the life of the plans.

21. Accordingly, Enbridge Gas adjusted the opening balance sheet at January 1, 2019, to record the $211 million balance previously recognized as AOCI in the financial records of Enbridge Gas as a regulatory asset (within the APCDA), instead of Goodwill. Enbridge Gas continues to draw down the regulatory asset by amortizing this balance as part of pension expense resulting in a regulatory asset balance of $169 million recognized in the APCDA at December 31, 2021. By continuing to follow this approach, Enbridge Gas ensures that its results during the deferred rebasing period reflect the accrual based pension expense recognized annually through amortization of the noted balance.

22. As noted in the EB-2020-0134 Interrogatory Response to LPMA[8], the amortization of actuarial gains/losses and past service costs is a component of accrual-based pension expense. Base rates for both the EGD and Union rate zones include a

[8] EB-2020-0134, Exhibit I.LPMA.4, page 2.

provision for accrual-based pension expenses as part of O&M. As communicated previously, commencing in 2019, the amortization of the unamortized actuarial gains/losses and past service costs through a drawdown of the pension balance in the APCDA results in the amortization continuing to form part of Enbridge Gas's overall pension expense, consistent to amortization that would have occurred prior to amalgamation.

23. Enbridge Gas proposes to continue the annual amortization and inclusion as part of the accrual based pension costs recognized as part of O&M expense (consistent with the amortization of actuarial gains/losses and past service costs incurred after the Enbridge/Spectra merger in 2017). This proposal will draw down the balance in the APCDA throughout the deferred rebasing period and will result in the recognition of annual pension expenses consistent with amounts that would have been recognized had the accounting change not been required (i.e. utility earnings are not impacted).

24. As indicated in 2019 and 2020, in a continuing effort to manage the impact to ratepayers, Enbridge Gas is continuing with this approach throughout the deferred rebasing period and will propose a methodology for disposal of the residual balance in the APCDA related to pension costs at December 31, 2023, as part of rebasing.

ENBRIDGE GAS - TAX VARIANCE DEFERRAL ACCOUNT

1. Establishment of the Enbridge Gas Inc. - Tax Variance Deferral Account was approved in the OEB's 2019 Rates (EB-2018-0305) Final Rate Order[1]. The purpose of this account is to record 50% of the revenue requirement impact of any tax rate changes, versus the tax rates included in rates that affect Enbridge Gas. In accordance with the OEB's July 25, 2019 letter, *Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance*, also accumulated in this account is 100% of the revenue requirement impact of any changes in Capital Cost Allowance (CCA) that are not reflected in base rates. This includes impacts related to Bill C-97 CCA rule changes, which became effective November 21, 2018, as well as any future CCA changes instituted by relevant regulatory or taxation bodies. Tax rate and CCA rule change impacts recorded in the account will, however, exclude tax rate and rule change impacts that are captured through other deferral account mechanisms (i.e., through the Incremental Capital Module Deferral Account and respective Capital Pass-through Project Deferral Accounts).

[1] EB-2018-0305, Final Rate Order dated October 24, 2019, Appendix I, page 10.

2. The balance in the Enbridge Gas Tax Variance Deferral Account at the end of 2021 is comprised of the following:

a. 2020 True up to T2 Filing balance[2]	$0.468 million
b. 2021 Non-integration related balance[3]	$18.694 million
c. 2020 Integration related balance[4]	$3.736 million
d. 2021 Integration related balance[5]	$10.463 million
Total Balance	$33.361 million

3. As noted above, the balance requested for clearance within this proceeding is a credit of $19.163 million[6], plus forecast interest of $0.227 million, for a total of $19.390 million. Of the principal balance in the account, $0.468 million relates to a true-up of the 2020 accelerated CCA impact, while $18.694 million relates to the 2021 accelerated CCA impact. The 2020 true-up amount reflects the impact of a variance between the 2020 qualifying additions captured in the 2020 Enbridge Gas Tax Variance Deferral Account examined in the EB-2021-0149 proceeding, and the final 2020 qualifying additions supporting EGI's 2020 tax filing. The accelerated CCA impacts of Bill C-97 were the only tax rate changes that impacted 2021.

4. As noted in the account description, the Tax Variance Deferral Account does not include the accelerated CCA impacts related to capital pass-through and incremental capital module projects, which have been reflected in the determination of variances recorded in deferral accounts associated with those respective projects.

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[2] Seeking approval to dispose of balance in this proceeding.
[3] Seeking approval to dispose of balance in this proceeding.
[4] Balance to be carried forward through end of 2023 per direction in EB-2021-0149 Settlement Decision.
[5] Balance to be carried forward through end of 2023 in line with decision on 2020 integration related balance.
[6] Sum of $0.468 million + $18.694 million.

5. Consistent with the OEB's EB-2021-0149 Decision and Order, dated January 27, 2021, the Tax Variance Deferral Account balance also includes the balances above that relate to accelerated CCA impacts of capital additions related to amalgamation/integration capital projects. Please see Exhibit C, Tab 1, Schedule 3 for continuity schedules supporting the calculation of the 2020 and 2021 accelerated CCA impacts of capital additions related to amalgamation/integration capital projects. The associated impacts of the annual integration related capital expenditures in 2020 and 2021 can be found in Exhibit B, Tab 3, Schedule 2. As per the direction in the Decision and Order, EGI will hold these cumulative balances in the account through 2023 and propose disposition within EGI's 2024 rebasing application.

1. Income Tax - Bill C-97 (Accelerated CCA)

6. To calculate the annual income tax (or earnings) impact of accelerated CCA, Enbridge Gas has maintained a continuity of the 2018 – 2021 total annual capital additions which have qualified for accelerated CCA, and then removed the annual additions related to capital pass-through and incremental capital module. For the remaining qualifying additions, the cumulative annual CCA has been calculated utilizing the accelerated rates and compared against the cumulative annual CCA calculated at the non-accelerated rates. The annual income tax (or earnings) impact of the variance between the two methodologies was then grossed-up for taxes to determine the annual revenue requirement impact. These annual impacts, representing 100% of the revenue requirement impact, have been recorded each year in the Enbridge Gas Inc. – Tax Variance Deferral Account. Please see Exhibit C, Tab 1, Schedule 3 for continuity schedules supporting the calculation of the 2021 accelerated CCA impact.

ENBRIDGE GAS – INTEGRATED RESOURCE PLANNNING OPERATING COSTS DEFERRAL ACCOUNT

1. On July 22, 2021, the OEB released its Decision and Order (EB-2020-0091) for Enbridge Gas' Integrated Resource Planning (IRP) Proposal. In this Decision, the OEB approved the establishment of an IRP Operating Costs Deferral Account for all IRP operations, maintenance, and administrations costs, and a separate IRP Capital Costs Deferral Account for IRP project plan costs.

2. On August 12, 2021, Enbridge Gas filed its draft accounting orders for the IRP Operating Costs Deferral Account and IRP Capital Cost Deferral Account. On September 2, 2021, the OEB found that the draft accounting orders were consistent with the Decision and Order and approved the accounts as filed.

3. The purpose of the IRP Operating Costs Deferral Account, as established in the OEB's EB-2020-0091 Decision and Order, is to record incremental IRP general administrative costs, as well as incremental operating and maintenance costs and ongoing evaluation costs for approved IRP Plans. Operating costs associated with approved IRP Plans would also include all enabling payments to service providers, made as part of the IRP Plans.

4. The balance in the 2021 IRP Operating Costs Deferral Account that is being requested for clearance within this proceeding is a debit of $0.058 million, plus forecast interest of $0.0005 million, for a total of $0.058 million. This amount is attributable to incremental Enbridge Gas staff salaries for IRP related work performed in 2021. The OEB in its IRP Decision approved "incremental IRP administrative costs required to meet the increased workload related to IRP"[1] … ' be treated as expenses and recorded in this account [operating costs deferral account]."[2]

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[1] EB-2020-0091, Decision and Order, page 71.
[2] EB-2020-0091, Decision and Order, page 75.

5. Since, this application is the first opportunity for Enbridge Gas to propose a rate allocation methodology for the IRP Operating Cost Deferral Account at Exhibit F, Tab 1, the account is being submitted for clearance despite the relatively modest amount incurred in 2021.

ENBRIDGE GAS
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym		Col. 1 Principal ($000's)	Col. 2 Interest ($000's)	Col. 3 Total ($000's)	Col.4 Reference
				Forecast for clearance at January 1, 2023			
	EGD Rate Zone Commodity Related Accounts						
1.	Storage and Transportation D/A	2021 S&TDA		7,942.5	97.0	8,039.5	D-1, Page 2
2.	Transactional Services D/A	2021 TSDA		(3,904.1)	(35.4)	(3,939.6)	D-1, Page 4
3.	Unaccounted for Gas V/A	2021 UAFVA		753.9	4.5	758.4	D-1, Page 6
4.	Total commodity related accounts			4,792.2	66.2	4,858.4	
	EGD Rate Zone Non Commodity Related Accounts						
5.	Average Use True-Up V/A	2021 AUTUVA		14,934.3	135.5	15,069.8	D-1, Page 10
6.	Gas Distribution Access Rule Impact D/A	2021 GDARIDA		-	-	-	D-1, Page 23
7.	Deferred Rebate Account	2021 DRA		4,359.4	53.5	4,412.9	D-1, Page 12
8.	Transition Impact of Accounting Changes D/A	2021 TIACDA		4,435.8	-	4,435.8	D-1, Page 1
9.	Electric Program Earnings Sharing D/A	2021 EPESDA		-	-	-	D-1, Page 23
10.	Open Bill Revenue V/A	2021 OBRVA		-	-	-	D-1, Page 23
11.	Ex-Franchise Third Party Billing Services V/A	2021 EXFTPBSVA		-	-	-	D-1, Page 23
12.	RNG Injection Service V/A	2021 RNGISVA		-	-	-	D-1, Page 23
13.	OEB Cost Assessment V/A	2021 OEBCAVA		2,550.3	31.5	2,581.8	D-1, Page 13
14.	Dawn Access Costs D/A	2021 DACDA		1,968.0	17.9	1,985.9	D-1, Page 16
15.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Dif	2021 P&OPEBFAVACPDVA		-	-	-	D-1, Page 23
16.	**Total EGD Rate Zone (for clearance)**			**33,040.0**	**304.5**	**33,344.6**	
	Union Rate Zones Gas Supply Accounts	OEB Account Number					
17.	Upstream Transportation Optimization	179-131	2021	8,616.3	78.2	8,694.5	E-1, Page 6
18.	Spot Gas Variance Account	179-107	2021	-	-	-	E-1, Page 58
19.	Unabsorbed Demand Costs Variance Account	179-108	2021	(1,665.6)	(28.3)	(1,693.9)	E-1, Page 1
20.	Base Service North T-Service TransCanada Capacity	179-153	2021	83.5	0.9	84.4	E-1, Page 52
21.	Total Gas Supply Accounts			7,034.2	50.8	7,085.0	
	Union Rate Zones Storage Accounts						
22.	Short-Term Storage and Other Balancing Services	179-70	2021	3,576.9	32.5	3,609.4	E-1, Page 8
	Union Rate Zones Other Accounts						
23.	Normalized Average Consumption	179-133	2021	18,997.4	239.4	19,236.8	E-1, Page 13
24.	Deferral Clearing Variance Account	179-132	2021	(3,120.4)	(45.3)	(3,165.7)	E-1, Page 21
25.	OEB Cost Assessment Variance Account	179-151	2021	907.1	11.4	918.5	E-1, Page 49
26.	Unbundled Services Unauthorized Storage Overrun	179-103	2021	-	-	-	E-1, Page 58
27.	Gas Distribution Access Rule Costs	179-112	2021	-	-	-	E-1, Page 58
28.	Conservation Demand Management	179-123	2021	-	-	-	E-1, Page 58
29.	Parkway West Project Costs	179-136	2021	(603.3)	(6.4)	(609.7)	E-1, Page 25
30.	Brantford-Kirkwall/Parkway D Project Costs	179-137	2021	(45.0)	(0.4)	(45.4)	E-1, Page 29
31.	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	2021	24.0	0.4	24.4	E-1, Page 41
32.	Lobo D/Bright C/Dawn H Compressor Project Costs	179-144	2021	(112.1)	(3.6)	(115.7)	E-1, Page 44
33.	Burlington-Oakville Project Costs	179-149	2021	(51.0)	(0.5)	(51.5)	E-1, Page 47
34.	Panhandle Reinforcement Project Costs	179-156	2021	(3,162.0)	(35.9)	(3,197.9)	E-1, Page 53
35.	Sudbury Replacement Project	179-162	2021	-	-	-	E-1, Page 58
36.	Parkway Obligation Rate Variance	179-138	2021	-	-	-	E-1, Page 58
37.	Unauthorized Overrun Non-Compliance Account	179-143	2021	-	-	-	E-1, Page 58
38.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Dif	179-157	2021	-	(1,345.6)	(1,345.6)	E-1, Page 56
39.	Unaccounted for Gas Volume Variance Account	179-135	2021	20,501.3	176.9	20,678.2	E-1, Page 31
40.	Unaccounted for Gas Price Variance Account	179-141	2021	3,358.3	31.8	3,390.1	E-1, Page 38
41.	Total Other Accounts			36,694.3	(977.8)	35,716.5	
42.	**Total Union Rate Zones (for clearance)**			**47,305.4**	**(894.6)**	**46,410.8**	
	EGI Accounts						
43.	Earnings Sharing D/A	179-382	2021	-	-	-	C-1, Page 1
44.	Tax Variance - Accelerated CCA - EGI	179-383	2021	(19,162.6)	(227.2)	(19,389.8)	C-1, Page 12
45.	IRP Operating Costs Deferral Account	179-385	2021	57.7	0.5	58.2	C-1, Page 15
46.	IRP Capital Costs Deferral Account	179-386	2021	-	-	-	C-1, Page 1
47.	Expansion of Natural Gas Distribution Systems V/A	179-380	2021	-	-	-	C-1, Page 1
48.	**Total EGI Accounts (for clearance)**			**(19,104.9)**	**(226.7)**	**(19,331.6)**	
49.	**Total Deferral and Variance Accounts (for clearance)**			**61,240.5**	**(816.7)**	**60,423.8**	
	Not Being Requested for Clearance						
50.	Accounting Policy Changes D/A - Pension - EGI	179-120	2021	169,431.8	-	169,431.8	C-1, Page 2
51.	Accounting Policy Changes D/A - Other - EGI	179-120	2019	(1,749.5)	(52.8)	(1,802.3)	C-1, Page 2
52.	Accounting Policy Changes D/A - Other - EGI	179-120	2020	(14,789.5)	(249.4)	(15,038.9)	C-1, Page 2
53.	Accounting Policy Changes D/A - Other - EGI	179-120	2021	(13,864.6)	(168.8)	(14,033.4)	C-1, Page 2
54.	Tax Variance - Integration Capital Additions - EGI	179-383	2020	(3,736.3)	(28.6)	(3,764.8)	C-1, Page 12
55.	Tax Variance - Integration Capital Additions - EGI	179-383	2021	(10,462.6)	(80.0)	(10,542.7)	C-1, Page 12
56.	Incremental Capital Module Deferral Account - EGD	2020 ICMDA	2020	(254.0)	(3.2)	(257.2)	C-1, Page 1
57.	Incremental Capital Module Deferral Account - EGD	2021 ICMDA	2021	175.5	2.0	177.5	C-1, Page 1
58.	Incremental Capital Module Deferral Account - UGL	179-159	2019	(6,869.6)	(196.1)	(7,065.7)	C-1, Page 1
59.	Incremental Capital Module Deferral Account - UGL	179-159	2020	(5,615.4)	(91.9)	(5,707.2)	C-1, Page 1
60.	Incremental Capital Module Deferral Account - UGL	179-159	2021	(14,353.4)	(147.2)	(14,500.6)	C-1, Page 1
61.	Impacts Arising from the COVID-19 Emergency D/A - EGI	2020 IACEDA	2020	1,377.5	20.3	1,397.8	C-1, Page 1
62.	Impacts Arising from the COVID-19 Emergency D/A - EGI	2021 IACEDA	2021	34.3	0.4	34.7	C-1, Page 1
63.	**Total of Accounts not being requested for clearance**			**99,324.2**	**(995.3)**	**98,328.9**	

ENBRIDGE GAS
SUMMARY OF ACCOUNTING POLICY CHANGES DEFERRAL ACCOUNT (NO. 179-381)
UTILITY REVENUE REQUIREMENT

Line No.	($000's)	Col. 1 EGD - Change from Capital to O&M	Col. 2 UGL - Change from O&M to Capital	Col. 3 Capitalization Policy Alignment - Subtotal	Col. 4 EGD - Change from IDC rate at WACD to Board Prescribed	Col. 5 UGL - Elimination of IDC Threshold	Col. 6 IDC Policy Alignment - Subtotal	Col. 7 Depreciation Expense Policy Alignment	Col. 8 EGD - Change in Overhead Capitalization	Col. 9 UGL - Change in Overhead Capitalization	Col. 10 Overhead Capitalization Alignment - Subtotal	Col. 11 **APCDA Total**	Col. 12 Actuarial Gains/Losses on UGL Pension
	Cost of capital												
1.	Rate base	(6,664.9)	7,367.8	702.9	(253.1)	1,745.5	1,492.4	9,416.5	(5,043.7)	13,439.8	8,396.1	**20,007.9**	-
2.	Required rate of return*	6.20%	7.30%		6.20%	7.30%		7.30%	6.20%	7.30%			7.30%
3.	Cost of capital*	(413.2)	537.8	124.6	(15.7)	127.4	111.7	687.4	(312.7)	981.1	668.4	**1,592.1**	-
	Cost of service												
4.	Gas costs	-	-	-	-	-	-	-	-	-	-	**-**	-
5.	Operation and Maintenance	916.2	(4,554.6)	(3,638.4)	-	-	-	-	4,513.3	(9,930.1)	(5,416.8)	**(9,055.2)**	(12,033.4)
6.	Depreciation and amortization	(162.0)	148.8	(13.2)	(7.3)	83.5	76.2	(4,881.5)	180.2	502.1	682.3	**(4,136.2)**	-
7.	Municipal and other taxes	-	-	-	-	-	-	-	-	-	-	-	-
8.	Cost of service	754.2	(4,405.8)	(3,651.6)	(7.3)	83.5	76.2	(4,881.5)	4,693.5	(9,428.0)	(4,734.5)	**(13,191.4)**	(12,033.4)
	Income taxes on earnings												
9.	Excluding tax shield	(128.3)	1,018.3	890.0	781.2	(430.4)	350.8	-	(670.3)	1,267.4	597.1	**1,837.9**	3,188.9
10.	Tax shield provided by interest expense	51.6	(78.1)	(26.5)	2.0	(18.5)	(16.5)	(99.8)	39.0	(142.5)	(103.5)	**(246.3)**	-
11.	Income taxes on earnings	(76.7)	940.2	863.5	783.2	(448.9)	334.3	(99.8)	(631.3)	1,124.9	493.6	**1,591.6**	3,188.9
	Taxes on (def) / suff.												
12.	Gross (def.) / suff.	(360.0)	3,983.7	3,623.7	(1,034.3)	323.7	(710.6)	5,842.0	(5,101.4)	9,961.9	4,860.5	**13,615.6**	12,033.4
13.	Net (def.) / suff.	(264.6)	2,928.0	2,663.4	(760.2)	237.9	(522.3)	4,293.9	(3,749.5)	7,322.0	3,572.5	**10,007.5**	8,844.5
14.	Taxes on (def.) / suff.	95.4	(1,055.7)	(960.3)	274.1	(85.8)	188.3	(1,548.1)	1,351.9	(2,639.9)	(1,288.0)	**(3,608.1)**	(3,188.9)
15.	Revenue requirement	359.7	(3,983.5)	(3,623.8)	1,034.3	(323.8)	710.5	(5,842.0)	5,101.4	(9,961.9)	(4,860.5)	**(13,615.8)**	(12,033.4)
16.	Gross revenue (def.) / suff.	(359.7)	3,983.5	3,623.8	(1,034.3)	323.8	(710.5)	5,842.0	(5,101.4)	9,961.9	4,860.5	**13,615.8**	12,033.4
											2020 True-Up to EGD IDC WACD rate	**248.8**	
											Total Booked to 2021 APCDA	**13,864.6**	

*Union rate zones 2013 Board-approved rate of return is 7.3% and EGD rate zone 2018 Board-approved rate of return is 6.2%.

ENBRIDGE GAS
CALCULATION OF THE BILL C-97 ACCELERATED CCA IMPACT TO BE RECORDED IN THE TAX VARIANCE DEFERRAL ACCOUNT

Line No.	Particulars ($000s) **2018 Year-End**		Opening UCC Accel. CCA	Opening UCC Regular CCA	Total Additions Qualifying for Accel. CCA	ICM & CPT Additions	CTA Additions	Additions Net of ICM CPT & CTA	Accel. CCA Depreciable UCC Balance	Regular CCA Depreciable UCC Balance	Rate (%)	Accelerated CCA	Regular CCA	Closing UCC Accel. CCA	Closing UCC Regular CCA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Class														
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	-	-	2,952.7	1,724.3	-	1,228.4	1,842.6	614.2	6%	110.6	36.9	1,117.8	1,191.5
3.	2	Mains acquired before 1988	-	-	-	-	-	-	-	-	6%	-	-	-	-
4.	3	Buildings acquired before 1988	-	-	-	-	-	-	-	-	5%	-	-	-	-
5.	6	Other buildings	-	-	-	-	-	-	-	-	10%	-	-	-	-
6.	7	Compression equipment acquired after February 22, 2005	-	-	7,775.4	4,438.3	-	3,337.0	5,005.6	1,668.5	15%	750.8	250.3	2,586.2	3,086.8
7.	8	Compression assets, office furniture, equipment	-	-	7,616.0	100.0	-	7,516.0	11,274.0	3,758.0	20%	2,254.8	751.6	5,261.2	6,764.4
8.	10	Transportation, computer equipment	-	-	1,874.7	-	-	1,874.7	2,812.0	937.3	30%	843.6	281.2	1,031.1	1,593.5
9.	12	Computer software, small tools	-	-	11,185.5	-	-	11,185.5	11,185.5	5,592.7	100%	11,185.5	5,592.7	-	5,592.7
10.	13	Leasehold improvements	-	-	-	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	-	-	82.0	-	-	82.0	122.9	41.0	5%	6.1	2.0	75.8	79.9
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	-	-	823.6	-	-	823.6	1,235.4	411.8	30%	370.6	123.5	453.0	700.1
15.	41	Storage assets	-	-	379.1	141.0	-	238.1	357.2	119.1	25%	89.3	29.8	148.8	208.4
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	-	-	1,870.0	584.3	-	1,285.6	1,928.5	642.8	8%	154.3	51.4	1,131.4	1,234.2
18.	50	Computers hardware acquired after March 18, 2007	-	-	2,286.8	-	-	2,286.8	3,430.1	1,143.4	55%	1,886.6	628.9	400.2	1,657.9
19.	51	Distribution pipelines acquired after March 18, 2007	-	-	62,357.7	1,078.0	-	61,279.7	91,919.5	30,639.8	6%	5,515.2	1,838.4	55,764.5	59,441.3
20.	Total		$ -	-	99,203.4	8,066.0	-	91,137.4	131,113.3	45,568.7		$ 23,167.4	$ 9,586.7	67,970.0	81,550.6

Line No.		Particulars ($000s) **2019 Year-End**	Opening UCC Accel. CCA	Opening UCC Regular CCA	Total Additions Qualifying for Accel. CCA	ICM & CPT Additions	CTA Additions	Additions Net of ICM CPT & CTA	Accel. CCA Depreciable UCC Balance	Regular CCA Depreciable UCC Balance	Rate (%)	Accelerated CCA	Regular CCA	Closing UCC Accel. CCA	Closing UCC Regular CCA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Class														
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	1,117.8	1,191.5	7,938.6	871.0	-	7,067.6	11,719.3	4,725.3	6%	703.2	283.5	7,482.3	7,975.6
3.	2	Mains acquired before 1988	-	-	-	-	-	-	-	-	6%	-	-	-	-
4.	3	Buildings acquired before 1988	-	-	-	-	-	-	-	-	5%	-	-	-	-
5.	6	Other buildings	-	-	-	-	-	-	-	-	10%	-	-	-	-
6.	7	Compression equipment acquired after February 22, 2005	2,586.2	3,086.8	6,244.1	5,218.0	-	1,026.1	4,125.3	3,599.8	15%	618.8	540.0	2,993.5	3,572.9
7.	8	Compression assets, office furniture, equipment	5,261.2	6,764.4	33,185.8	15,202.5	-	17,983.3	32,236.2	15,756.1	20%	6,447.2	3,151.2	16,797.3	21,596.5
8.	10	Transportation, computer equipment	1,031.1	1,593.5	16,254.8	-	-	16,254.8	25,413.3	9,720.9	30%	7,624.0	2,916.3	9,661.9	14,932.0
9.	12	Computer software, small tools	-	5,592.7	36,263.7	-	-	36,263.7	36,263.7	23,724.6	100%	36,263.7	23,724.6	-	18,131.8
10.	13	Leasehold improvements	-	-	-	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	75.8	79.9	3,595.8	1,836.0	-	1,759.8	2,715.5	959.8	5%	135.8	48.0	1,699.8	1,791.7
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	453.0	700.1	4,166.1	-	-	4,166.1	6,702.1	2,783.1	30%	2,010.6	834.9	2,608.4	4,031.2
15.	41	Storage assets	148.8	208.4	735.5	-	-	735.5	1,252.1	576.1	25%	313.0	144.0	571.3	799.8
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	1,131.4	1,234.2	90,992.5	55,507.0	-	35,485.5	54,359.6	18,977.0	8%	4,348.8	1,518.2	32,268.1	35,201.6
18.	50	Computers hardware acquired after March 18, 2007	400.2	1,657.9	29,431.1	-	-	29,431.1	44,546.9	16,373.5	55%	24,500.8	9,005.4	5,330.5	22,083.6
19.	51	Distribution pipelines acquired after March 18, 2007	55,764.5	59,441.3	499,719.3	988.6	-	498,730.7	803,860.5	308,806.6	6%	48,231.6	18,528.4	506,263.5	539,643.6
20.	Total		$ 67,970.0	81,550.6	728,527.3	79,623.1	-	648,904.2	1,023,194.5	406,002.8		$ 131,197.5	$ 60,694.5	585,676.7	669,760.4

Line No.		Particulars ($000s) 2020 Year-End	Opening UCC Accel. CCA	Opening UCC Regular CCA	Total Additions Qualifying for Accel. CCA	ICM & CPT Additions	CTA Additions	Additions Net of ICM CPT & CTA	Accel. CCA Depreciable UCC Balance	Regular CCA Depreciable UCC Balance	Rate (%)	Accelerated CCA	Regular CCA	Closing UCC Accel. CCA	Closing UCC Regular CCA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Class														
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	7,482.3	7,975.6	5,806.2	18.0	-	5,788.2	16,164.5	10,869.7	6%	969.9	652.2	12,300.6	13,111.6
3.	2	Mains acquired before 1988	-	-	-	-	-	-	-	-	6%	-	-	-	-
4.	3	Buildings acquired before 1988	-	-	-	-	-	-	-	-	5%	-	-	-	-
5.	6	Other buildings	-	-	-	-	-	-	-	-	10%	-	-	-	-
6.	7	Compression equipment acquired after February 22, 2005	2,993.5	3,572.9	3,939.1	109.0	-	3,830.1	8,738.6	5,487.9	15%	1,310.8	823.2	5,512.8	6,579.8
7.	8	Compression assets, office furniture, equipment	16,797.3	21,596.5	43,271.3	4,233.9	-	39,037.4	75,353.4	41,115.2	20%	15,070.7	8,223.0	40,764.0	52,410.9
8.	10	Transportation, computer equipment	9,661.9	14,932.0	5,546.8	-	-	5,546.8	17,982.1	17,705.4	30%	5,394.6	5,311.6	9,814.1	15,167.2
9.	12	Computer software, small tools	-	18,131.8	11,365.0	-	777.1	10,587.9	10,587.9	23,425.8	100%	10,587.9	23,425.8	-	5,293.9
10.	13	Leasehold improvements	-	-	-	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	1,699.8	1,791.7	2,214.1	199.4	-	2,014.7	4,721.9	2,799.1	5%	236.1	140.0	3,478.5	3,666.5
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	2,608.4	4,031.2	11,910.1	-	-	11,910.1	20,473.6	9,986.3	30%	6,142.1	2,995.9	8,376.4	12,945.4
15.	41	Storage assets	571.3	799.8	30,035.1	16.0	-	30,019.1	45,600.0	15,809.4	25%	11,400.0	3,952.4	19,190.4	26,866.6
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	32,268.1	35,201.6	80,470.1	8,582.4	-	71,887.7	140,099.7	71,145.4	8%	11,208.0	5,691.6	92,947.8	101,397.7
18.	50	Computers hardware acquired after March 18, 2007	5,330.5	22,083.6	40,091.6	-	18,135.0	21,956.6	38,265.5	33,061.9	55%	21,046.0	18,184.1	6,241.1	25,856.2
19.	51	Distribution pipelines acquired after March 18, 2007	506,263.5	539,643.6	639,216.7	50,127.7	-	589,089.1	1,389,897.2	834,188.1	6%	83,393.8	50,051.3	1,011,958.8	1,078,681.3
20.		Total	$ 585,676.7	669,760.4	873,866.1	63,286.3	18,912.2	791,667.7	1,767,884.3	1,065,594.3		$ 166,759.8	$ 119,451.0	1,210,584.6	1,341,977.1

Line No.		2021 Year-End Particulars ($000s)	Opening UCC Accel. CCA	Opening UCC Regular CCA	Total Additions Qualifying for Accel. CCA	ICM & CPT Additions	CTA Additions	Additions Net of ICM CPT & CTA	Accel. CCA Depreciable UCC Balance	Regular CCA Depreciable UCC Balance	Rate (%)	Accelerated CCA	Regular CCA	Closing UCC Accel. CCA	Closing UCC Regular CCA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Class														
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	12,300.6	13,111.6	31,455.0	-	1,723.1	29,731.9	56,898.5	27,977.6	6%	3,413.9	1,678.7	38,618.6	41,164.9
3.	2	Mains acquired before 1988	-	-	-	-	-	-	-	-	6%	-	-	-	-
4.	3	Buildings acquired before 1988	-	-	-	-	-	-	-	-	5%	-	-	-	-
5.	6	Other buildings	-	-	-	-	-	-	-	-	10%	-	-	-	-
6.	7	Compression equipment acquired after February 22, 2005	5,512.8	6,579.8	5,851.4	-	-	5,851.4	14,289.9	9,505.5	15%	2,143.5	1,425.8	9,220.7	11,005.4
7.	8	Compression assets, office furniture, equipment	40,764.0	52,410.9	15,737.5	7,849.8	53.3	7,834.3	52,515.5	56,328.1	20%	10,503.1	11,265.6	38,095.3	48,979.6
8.	10	Transportation, computer equipment	9,814.1	15,167.2	13,440.2	-	-	13,440.2	29,974.3	21,887.3	30%	8,992.3	6,566.2	14,261.9	22,041.2
9.	12	Computer software, small tools	-	5,293.9	76,510.3	-	53,798.4	22,711.9	22,711.9	16,649.9	100%	22,711.9	16,649.9	-	11,356.0
10.	13	Leasehold improvements	-	-	-	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	3,478.5	3,666.5	2,802.8	18.9	-	2,784.0	7,654.4	5,058.5	5%	382.7	252.9	5,879.7	6,197.5
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	8,376.4	12,945.4	5,402.9	-	-	5,402.9	16,480.9	15,646.9	30%	4,944.3	4,694.1	8,835.1	13,654.3
15.	41	Storage assets	19,190.4	26,866.6	54,897.2	-	-	54,897.2	101,536.3	54,315.2	25%	25,384.1	13,578.8	48,703.6	68,185.0
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	92,947.8	101,397.7	75,856.8	-	-	75,856.8	206,733.0	139,326.0	8%	16,538.6	11,146.1	152,266.0	166,108.3
18.	50	Computers hardware acquired after March 18, 2007	6,241.1	25,856.2	7,950.3	-	14,327.6	(6,377.3)	(3,324.8)	22,667.5	55%	(1,828.6)	12,467.1	1,692.5	7,011.7
19.	51	Distribution pipelines acquired after March 18, 2007	1,011,958.8	1,078,681.3	810,728.0	104,174.2	-	706,553.7	2,071,789.4	1,431,958.2	6%	124,307.4	85,917.5	1,594,205.2	1,699,317.6
20.		Total	$ 1,210,584.6	1,341,977.1	1,100,632.4	112,042.9	69,902.3	918,687.2	2,577,259.4	1,801,320.7		$ 217,493.1	$ 165,642.7	1,911,778.6	2,095,021.6

	2018	2019	2020	2021
CCA Variance (i) - (j)	13,580.7	70,503.0	47,308.8	51,850.4
Tax Rate	26.5%	26.5%	26.5%	26.5%
Earnings Impact of Accelerated CCA	3,598.9	18,683.3	12,536.8	13,740.4
Earnings Impact Grossed-up for Taxes Recorded in the TVDA	4,896.4	25,419.4	17,056.9	18,694.4
Balances as filed in EB-2021-0149	4,896.4	25,133.9	16,588.8	N/A
variance	-	285.5	468.2	-
Include adjustment to 2019 balance in 2020 TVDA	-	(285.5)	285.5	-
Include adjustment to 2020 balance in 2021 TVDA	-	-	(468.2)	468.2
Revised Balances	4,896.4	25,133.9	16,874.2	19,162.6

1 - Balance for 2019 was updated based on the change from EB-2020-0134 and Tax Filing on June 30, 2020.
2 - Balance for 2020 was updated based on the change from EB-2021-0149 and Tax Filing on June 30, 2021.

2020 Year-End - Integration Capital Additions

Line No.	Class	Particulars ($000s)	Opening UCC Accel. CCA (a)	Opening UCC Regular CCA (b)	CTA Additions (c)	Accel. CCA Depreciable UCC Balance (d)	Regular CCA Depreciable UCC Balance (e)	Rate (%) (f)	Accelerated CCA (g)	Regular CCA (h)	Closing UCC Accel. CCA (i)	Closing UCC Regular CCA (j)
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	-	-	-	-	-	6%	-	-	-	-
3.	2	Mains acquired before 1988	-	-	-	-	-	6%	-	-	-	-
4.	3	Buildings acquired before 1988	-	-	-	-	-	5%	-	-	-	-
5.	6	Other buildings	-	-	-	-	-	10%	-	-	-	-
6.	7	Compression equipment acquired after February 22, 2005	-	-	-	-	-	15%	-	-	-	-
7.	8	Compression assets, office furniture, equipment	-	-	-	-	-	20%	-	-	-	-
8.	10	Transportation, computer equipment	-	-	-	-	-	30%	-	-	-	-
9.	12	Computer software, small tools	-	-	777.1	777.1	388.6	100%	777.1	388.6	-	388.6
10.	13	Leasehold improvements	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	-	-	-	-	-	5%	-	-	-	-
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	-	-	-	-	-	30%	-	-	-	-
15.	41	Storage assets	-	-	-	-	-	25%	-	-	-	-
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	-	-	-	-	-	8%	-	-	-	-
18.	50	Computers hardware acquired after March 18, 2007	-	-	18,135.0	27,202.5	9,067.5	55%	14,961.4	4,987.1	3,173.6	13,147.9
19.	51	Distribution pipelines acquired after March 18, 2007	-	-	-	-	-	6%	-	-	-	-
20.		Total	$ -	-	18,912.2	27,979.7	9,456.1		$ 15,738.5	$ 5,375.7	3,173.6	13,536.5

2021 Year-End - Integration Capital Additions

Line No.	Class	Particulars ($000s)	Opening UCC Accel. CCA (a)	Opening UCC Regular CCA (b)	CTA Additions (c)	Accel. CCA Depreciable UCC Balance (d)	Regular CCA Depreciable UCC Balance (e)	Rate (%) (f)	Accelerated CCA (g)	Regular CCA (h)	Closing UCC Accel. CCA (i)	Closing UCC Regular CCA (j)
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	-	-	1,723.1	2,584.6	861.5	6%	155.1	51.7	1,568.0	1,671.4
3.	2	Mains acquired before 1988	-	-	-	-	-	6%	-	-	-	-
4.	3	Buildings acquired before 1988	-	-	-	-	-	5%	-	-	-	-
5.	6	Other buildings	-	-	-	-	-	10%	-	-	-	-
6.	7	Compression equipment acquired after February 22, 2005	-	-	-	-	-	15%	-	-	-	-
7.	8	Compression assets, office furniture, equipment	-	-	53.3	79.9	26.6	20%	16.0	5.3	37.3	48.0
8.	10	Transportation, computer equipment	-	-	-	-	-	30%	-	-	-	-
9.	12	Computer software, small tools	-	388.6	53,798.4	53,798.4	27,287.8	100%	53,798.4	27,287.8	-	26,899.2
10.	13	Leasehold improvements	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	-	-	-	-	-	5%	-	-	-	-
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	-	-	-	-	-	30%	-	-	-	-
15.	41	Storage assets	-	-	-	-	-	25%	-	-	-	-
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	-	-	-	-	-	8%	-	-	-	-
18.	50	Computers hardware acquired after March 18, 2007	3,173.6	13,147.9	14,327.6	24,665.0	20,311.7	55%	13,565.7	11,171.4	3,935.5	16,304.0
19.	51	Distribution pipelines acquired after March 18, 2007	-	-	-	-	-	6%	-	-	-	-
20.		Total	$ 3,173.6	13,536.5	69,902.3	81,127.9	48,487.6		$ 67,535.2	$ 38,516.2	5,540.7	44,922.6

	2020	2021
CCA Variance (i) - (j)	10,362.8	29,019.0
Tax Rate	26.5%	26.5%
Earnings Impact of Accelerated CCA	2,746.1	7,690.0
Earnings Impact Grossed-up for Taxes Related to Integrated Capital Additions	3,736.3	10,462.6

2022 TRANSITION IMPACT OF ACCOUNTING CHANGES DEFERRAL ACCOUNT – EGD RATE ZONE

1. The purpose of the Transition Impact of Accounting Changes Deferral Account (TIACDA) is to track the un-cleared Other Post Employment Benefit (OPEB) costs which the OEB has approved for recovery. Within EB-2011-0354, the OEB approved the recovery of OPEB costs, which were forecast to be $90 million at the end of 2012, evenly over a 20-year period, commencing in 2013. The OPEB costs needed to be recognized as a result of EGD having to account for post-employment expenses on an accrual basis, upon transition to USGAAP for corporate reporting purposes in 2012. The use of USGAAP for regulatory purposes was approved within the 2013 rate proceeding, EB-2011-0354.

2. The final amount recorded in the TIACDA as of the end of 2012 was $88.716 million. The first nine installments (for each of 2013 through 2021) of $4.436 million each (1/20 of $88.716 million), were approved for recovery within the EB-2013-0046, EB-2014-0195, EB-2015-0122, EB-2016-0142, EB-2017-0102, EB-2018-0131, EB-2019-0105, EB-2020-0134, and EB-2021-0149 proceedings.

3. Enbridge Gas is now requesting recovery of the tenth, or 2022 installment of the OEB-Approved TIACDA amount, in the amount of $4.436 million (1/20 of $88.716 million). As per the approved description and scope of the account, interest is not applicable to the balances to be cleared from the TIACDA.

2021 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT
EGD RATE ZONES

1. The purpose of the 2021 Storage & Transportation Deferral Account (S&TDA) is to record the difference between the forecast cost of Storage and Transportation included in the Company's approved rates and the actual cost of Storage and Transportation incurred by the Company. Storage and Transportation cost includes cost of service and market-based pricing.

2. The S&TDA also records the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, the S&TDA is used to record amounts received by the Company related to deferral account dispositions of other utilities deferral accounts.

3. The balance in the 2021 S&TDA that the Company is proposing to collect from customers is $7.9 million plus interest. A detailed breakdown of the S&TDA is provided in Exhibit D, Tab 1, Schedule 1.

4. The primary driver for the balance in the 2021 S&TDA is higher than forecasted transportation prices and higher than forecasted market-based storage costs in 2021, partially offset by a $1.6M refund from the Union rate zone as part of Union's 2019 deferral disposition. Transportation prices are determined by the OEB-approved M12 Rate Schedule.

5. As outlined in the 2021 Annual Update to the 5 Year Gas Supply Plan, Enbridge Gas purchases market-based storage services on behalf of customers in the EGD rate zone through a competitive blind storage RFP process. On January 4, 2021, Enbridge Gas initiated an RFP for market-based storage capacity with deliveries to Dawn. The RFP was conducted by Guidehouse Inc. The RFP requested offers of storage services with terms of up to 5 years commencing April 1, 2021 with firm

injections from May to September and firm withdrawals from December to March. The RFP letter is provided as Exhibit D, Tab 1, Schedule 5.

6. Enbridge Gas required this annual replacement of third-party storage in order to reliably and cost effectively meet demand on peak winter days as well as retain late season deliverability. The RFP responses were received by Enbridge Gas on January 25, 2021 with conforming offers from three different counterparties with multiple terms, prices and injection/withdrawal parameters. The RFP manager made the recommendation and Enbridge Gas transacted based on the recommendation. Bids received and those that were selected are outlined in Confidential Exhibit D, Tab 1, Schedule 6.

2021 TRANSACTIONAL SERVICES DEFERRAL ACCOUNT
EGD RATE ZONE

1. The concept of Transactional Services operates under the premise that if circumstances arise where the assets acquired by Enbridge Gas to meet customer demand are not fully required then those assets can be made available to generate third party revenue. Transactional Services are the optimization of these assets.

2. Transactional Services optimization can be grouped into two different categories – storage optimization and transportation optimization. Storage optimization transactions typically rely on the storage of or the loan of gas between two points in time at the same location (i.e. Dawn). Transportation optimization transactions typically rely on the exchange of gas on the day between two locations.

3. Any revenues received from Transactional Services are to be shared 90:10 between the ratepayer and the Company. The EGD rate zone rates include an upfront benefit of $12.0 million in Transactional Services revenue that has been applied to reduce the overall costs to be collected from EGD rate zone ratepayers. The purpose of the TSDA is to capture the difference between the total ratepayer share of transactional services revenue and the amount already included in rates.

4. During 2021 the Company generated a total of $17.5 million in net Transactional Services revenue, of which the ratepayer portion represents $15.8 million, through a combination of Storage and Transportation Optimization. Exhibit D, Tab 1, Schedule 2 provides a breakdown of Transactional Services revenue by type of transaction, and sets out the details of the amount, $3.8 million proposed to be credited to customers through the disposition of the 2021 TSDA. For comparison purposes the schedule also includes amounts recorded in the applicable TSDA accounts for years 2020, 2019, 2018, and 2017.

5. The transactions that Enbridge Gas entered into in 2021 contained the three elements of Transactional Services as were described in the Company's evidence in EB-2013-0046 in that they were unplanned, the result of a Third-Party service request and were available because of temporary surplus capacity.

2021 UNACCOUNTED-FOR GAS VARIANCE ACCOUNT
EGD RATE ZONE

1. This evidence provides the volumetric variance underpinning the balance in the 2021 Unaccounted-For Gas Variance Account (UAFVA). It will describe the 2021 variance relative to historical Unaccounted-For Gas (UAF) volumes for the EGD rate zone.

2. UAF is the difference between natural gas delivered into the distribution system as billed by third-party transmission entities (namely, TC Energy and Union Gas[1]), and natural gas consumed by the customers in the EGD rate zone and EGD own use gas and line pack gas. Owing to its residual nature, UAF cannot be measured directly. UAF can arise from meter differences, operational or external factors such as line leakage, unmetered uses, and third party damages. In addition, because gas volumes are affected by temperature and pressure, measurement is made more difficult.

3. The 2021 level of UAF for the EGD rate zone was determined to be 115,553 10^3m^3. The variance of 8,876 10^3m^3, which is the difference between actual UAF volume and the forecast UAF volume of 106,677 10^3m^3, underpins the $0.7 million balance that is captured in the UAFVA. Exhibit D, Tab 1, Schedule 3 provides the detail calculations of the UAFVA balance.

4. The 2019 UAF study was filed as part of the 2020 rate application (EB-2019-0194). The report found that the primary sources for UAF include physical losses, retail meter variation and gate station meter variations. The report noted that

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[1] As of January 1, 2019, Union Gas Limited and Enbridge Gas Distribution merged to become Enbridge Gas Inc.

Enbridge Gas' UAF levels are generally lower than competitive gas utilities over the past 10 years. The year-to-year fluctuations are a result of many factors including weather, estimation variation, measurement variation, and billing and accounting adjustments. The practices and initiatives to monitor and manage sources of UAF are generally consistent with those of other gas utilities. As part of the Decision and Order for the 2020 rate application (EB-2019-0194), EGI agreed to provide a "progress report" about the implementation of the UFG report recommendations in its 2022 rates application. A UFG Progress Report was filed as part of EB-2021-0148. The OEB noted that issues related to UFG were out of scope in the 2022 rate application, noting Enbridge Gas's commitment "to assess its UFG forecasting methodology in the 2024 rebasing proceeding and to include information about the implementation of the UFG Report recommendations and other activities to address UFG, and the impacts of such activities."

5. As shown in Tables 1 and 2 in the following pages, UAF within the EGD rate zone has been quite volatile over the years, showing some stability from 2010-2012, and followed by higher levels especially in 2014, 2016, 2018 and 2019. The 2021 UAF level falls within the 95% confidence interval, bounded by (9,125) 10^3m^3 and 167,748 10^3m^3.

Table 1: Unaccounted-For Gas Volumes (10^3 m^3), 1991-2021

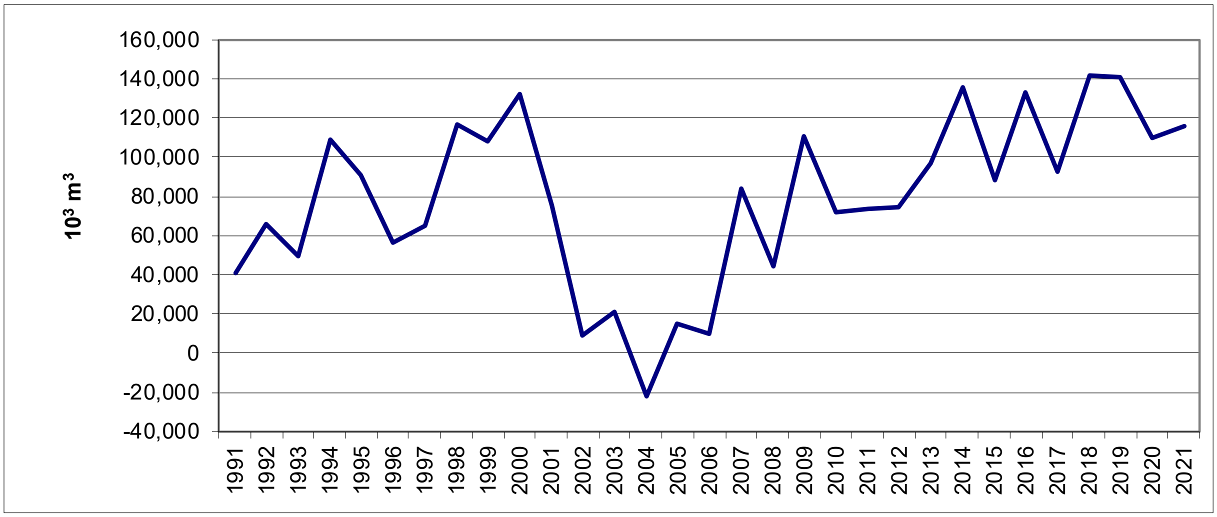

Table 2

Col.1	*Col.2*
Calendar Year	**UAF Volumes (10^3 m^3)**
1991	40,662
1992	66,028
1993	49,782
1994	108,765
1995	90,655
1996	56,739
1997	65,228
1998	116,376
1999	108,201
2000	132,021
2001	75,606
2002	9,284
2003	21,412
2004	-22,406
2005	14,815
2006	10,274
2007	83,823
2008	44,424
2009	110,917
2010	72,104
2011	73,355
2012	74,762
2013	97,361
2014	135,380
2015	88,438
2016	133,112
2017	93,077
2018	142,086
2019	140,594
2020	110,234
2021	115,553

	1991-2021
Standard deviation	43,098
Mean	79,312
Lower bound*	-9,125
Upper bound*	167,748

*95% confidence interval with 27 degrees of freedom (number of observations-1)

2021 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT
EGD RATE ZONE

1. The purpose of this evidence is to provide information in support of the 2021 Average Use True-up Variance Account (AUTUVA) balance.

2. Exhibit D, Tab 1, Schedule 4 details the calculations of the $14.93 million that will be collected from ratepayers. The collection is attributable to actual Rate 1 (residential) and Rate 6 (apartment, small commercial and industrial) average uses being lower than 2021 forecast levels.

3. Lower weather-normalized average uses are primarily attributable to higher actual natural gas prices and worse economic conditions than were forecast for 2021. Higher gas prices and lower employment growth have led to lower consumption for both Rate 1 and Rate 6 customers. Rate 6 customers and their consumption patterns are heavily impacted by the economic conditions under the COVID-19 pandemic. Lower GDP growth and higher (doubled) commercial vacancy rates in 2021 than were expected have been other factors which also contributed to lower average use for Rate 6 customers.

4. The purpose of the AUTUVA is to record (true-up) the revenue impact (exclusive of gas costs) of the normalized volumetric difference between the forecast of average use per customers in Rate 1 and Rate 6 and the actual weather-normalized average use experienced during the year. The revenue impact is calculated using a unit rate determined in the same manner as the impact used in the derivation of the Lost Revenue Adjustment Mechanism (LRAM).

5. As detailed in Exhibit D, Tab 1, Schedule 4, the calculation of the volumetric variance between forecast average use and actual normalized average use subtracts the volumetric impact of Demand Side Management (DSM) programs in the year. As has been the case in previous applications, since the audited actual volume savings of 2021 DSM activities will not be available until a later date, the 2021 OEB-Approved Budget DSM volumes are used as an estimate of 2021 actuals. Without the exclusion of a DSM volumetric variance in the AUTUVA calculation, the impacts of DSM are inherently included. As a result, 2021 LRAM amounts which will be filed at a later date, will exclude the impact of Rate 1 and Rate 6 customers.

2021 DEFERRED REBATE ACCOUNT
EGD RATE ZONE

1. The purpose of the 2021 Deferred Rebate Account (DRA), consistent with prior fiscal years, was to record any amounts payable to, or receivable from, EGD rate zone customers as a result of clearing Deferral and Variance Accounts, which remain outstanding due to the inability to locate such customers.

2. During 2021, the Company cleared 2017 and 2018 DSM related deferral accounts, approved as part of the EB-2020-0067 proceeding, over the April through June 2021 period. In addition, 2019 DSM related deferral accounts approved as part of the EB-2021-0072 proceeding, as well as the 2019 deferral accounts approved as part of the EB-2020-0134 proceeding, were cleared in October 2021.

3. The $4.4 million recorded in the 2021 DRA and requested for clearance (and corresponding interest of $53.5 thousand), reflects the outstanding amount resulting from the clearance of deferral and variance accounts in the EGD rate zone which occurred during 2021 and the inability to locate all the intended customers.

2021 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT EGD RATE ZONE

1. The purpose of the 2021 Ontario Energy Board Cost Assessment Variance Account (OEBCAVA) was to record any material variances between the OEB costs assessed to Enbridge Gas (relevant to the EGD rate zone) through application of the revised Cost Assessment Model (CAM), which became effective April 1, 2016, and the OEB costs which were included in EGD rate zone rates, which were determined through application of the prior Cost Assessment Model. The scope of the account is consistent with prior OEBCAVAs. However, in accordance with the EB-2020-0134 OEB-approved Settlement Proposal[1], in EGI's 2019 Earnings Sharing and Deferral Disposition proceeding, the base OEB costs assumed to be included in rates have been escalated to the reflect the growth in the amount recovered through rates, which results from annual price cap adjustments and customer growth. The OEBCAVA was originally approved for establishment by an OEB letter dated February 9, 2016, entitled: *Revisions to the Ontario Energy Board Cost Assessment Model.*

2. The amount recorded within the 2021 OEBCAVA is $2.550 million, plus interest of $0.032 million for a total debit balance of $2.582 million. This amount reflects the variance between OEB costs assessed to Enbridge Gas (relevant to EGD rate zone) in each quarter of fiscal 2021, utilizing the revised CAM, and EGD's average quarterly OEB cost assessment under the prior CAM, escalated in accordance with the EB-2020-0134 OEB-approved Settlement Proposal.

3. In order to calculate the amount to be recovered through the 2021 EGD rate zone OEBCAVA, the Company first needed to apportion the actual 2021 OEB assessed costs between the legacy rate zones. Commencing with the OEB's 2019 / 2020

[1] EB-2020-0134, Decision on Settlement Proposal, January 25, 2021, pages 5-6.

fiscal first quarter assessment (for the period April 1, 2019 through June 30, 2019), and continuing since, EGI has been receiving one consolidated quarterly bill for the amalgamated utility. To apportion the quarterly assessments received in 2021 between rate zones, the assessments were prorated based on the total invoices received by each legacy utility for the OEB's 2018 / 2019 fiscal year (for the period April 1, 2018 through March 31, 2019), the final year for which the OEB issued invoices to each legacy utility. Table 1 below shows the proration of the OEB's 2018 / 2019 fiscal year assessments between each legacy utility / rate zone (59.76% EGD rate zone, 40.24% Union rate zones). Table 2 shows the apportionment of EGI's 2021 assessed costs to the EGD rate zone, and the calculation of the amount recorded in the 2021 EGD rate zone OEBCAVA.

4. To calculate the amount for recovery through the 2021 EGD rate zone OEBCAVA, the Company also needed to establish the base comparator, reflecting the OEB costs included in EGD rate zone rates, determined through application of the prior Cost Assessment Model. In accordance with the EB-2020-0134 OEB-approved Settlement Proposal, the amount reflected in rates is to be increased, or escalated, to reflect the growth in the amount recovered as a result of annual price cap adjustments and customer growth. To establish the 2021 base comparator, the Company escalated the 2020 quarterly comparator of $0.773 million by the sum of the 2021 Price Cap Index (PCI) of 1.70%, and the EGD rate zone ICM threshold calculation Growth Factor (g) of 1.73%, which were approved as part of EGI's 2021 Rate Application (EB-2020-0181). The escalation resulted in a 2021 quarterly comparator of $0.799 million ($0.773 million * (1 + (1.70% + 1.73%))). As noted above, Table 2 below shows the apportionment of EGI's actual 2021 assessed costs to the EGD rate zone, and the calculation of the amount recorded in the 2021 EGD rate zone OEBCAVA utilizing a base comparator of $0.799 million.

5. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2021 OEBCAVA, in the amount of $2.550 million and $0.032 million respectively, as shown in Exhibit C, Tab 1, Schedule 1.

Table 1

OEB 2018/2019 Cost Assessments

	EGD	UGL	Total
Apr. 1 to Jun. 30, 2018	1,467,963.00	988,479.00	2,456,442.00
Jul. 1 to Sep. 30, 2018	1,356,860.00	913,873.00	2,270,733.00
Oct. 1 to Dec. 31, 2018	1,356,860.00	913,873.00	2,270,733.00
Jan. 1 to Mar. 31, 2019	1,356,860.00	913,873.00	2,270,733.00
	5,538,543.00	3,730,098.00	9,268,641.00
Percentage of Total	59.76%	40.24%	100.00%

Table 2

Calculation of 2021 EGD RZ OEBCAVA

Period	EGI Assessment	EGD Rate Zone Share (59.76%)	Average cost assessment Comparator	Variance to UGL Rate Zone OEBCAVA
Jan. 1 to Mar. 31, 2021	2,497,219.00	1,492,231.15	799,494.06	692,737.09
Apr. 1 to Jun. 30, 2021	2,364,191.00	1,412,739.31	799,494.06	613,245.25
Jul. 1 to Sep. 30, 2021	2,379,076.00	1,421,633.95	799,494.06	622,139.89
Oct. 1 to Dec. 31, 2021	2,379,076.00	1,421,633.95	799,494.06	622,139.89
				2,550,262.12

2021 DAWN ACCESS COSTS DEFERRAL ACCOUNT
EGD RATE ZONE

1. The purpose of the Dawn Access Costs Deferral Account (DACDA), as established in the EB-2014-0323 Settlement Agreement, was to record for recovery the revenue requirement impact of the incremental costs incurred to implement the Dawn Transportation Service (DTS), including the costs for required system changes. In addition, in accordance with Legacy EGD's 2017 Rate Application Settlement Proposal (EB-2016-0215) the revenue requirement related to additional costs incurred to accommodate the heat value conversion modification, implemented in conjunction with the Dawn Transportation Service system development process, were also to be recorded within this account. Under the terms of the EB-2014-0323 Settlement Agreement, recovery of amounts recorded in the DACDA will be from all bundled customers, regardless of whether they are system or direct purchase and regardless of the service to which they currently subscribe, because all have the option of taking DTS if they so choose. Further details explaining the DACDA, including the recovery method, are included within Section 2.7 of the Settlement Agreement filed at Exhibit B, Tab 2, Schedule 1 of the EB-2014-0323 proceeding.

2. As was indicated in the EB-2018-0131, EB-2019-0105, EB-2020-0134, and EB-2021-0149 proceedings (in support of the clearance of the 2017 through 2020 revenue requirement amounts recorded in the 2017 through 2020 DACDAs), all incremental costs incurred by the Company to implement the DTS (and functionality for 2 additional receipt points) and heat value conversion modification were capital in nature. Capital costs of $6.5 million were incurred to develop, test, and integrate enhancements to the functionality of Enbridge's EnTRAC and connected systems. The systems modifications were placed into service effective November 1, 2017, in conjunction with the implementation of Phase 2 of the Dawn

Access Settlement. The annual revenue requirement amounts sought for refund/recovery in association with those capital costs, includes the typical items in a cost of service revenue requirement, such as total return on rate base, including interest and return on equity, depreciation, and income taxes.

3. Within this proceeding, the Company is requesting clearance of the 2021 revenue requirement, or principal balance, of $1.968 million (and corresponding interest of $0.0179 million) as part of the requested one-time rate rider adjustment in January 2023, as shown in the proposed clearance balances at Exhibit C, Tab 1, Schedule 1. As indicated above, this amount represents the 2021 revenue requirement associated with the capital spending incurred to accommodate the DTS and heat value changes, which were placed into service in 2017. The Company has used the 2021 actual required capital structure within the 2021 revenue requirement calculation (consistent with the use of the actual capital structures which were utilized in determining previous revenue requirements which were approved for clearance). There will also be revenue requirement amounts to be recorded in relation to this spending in 2022, at which point the costs will be fully depreciated. The 2021 amount was slightly lower than 2020, due to a declining rate base value and lower required rate of return resulting in a lower cost of capital, but was higher than 2017 and 2018 as both years' revenue requirements benefited from a significant Capital Cost Allowance (CCA) tax deduction that does not repeat in subsequent years beyond 2018.

4. The revenue requirement sought for recovery will be allocated to the various rate classes based on the bundled annual deliveries of each rate class.

5. The determination of the 2021 DACDA revenue requirement deferral account amount and related costs are shown below. The approved 2017, 2018, 2019 & 2020 revenue requirement amounts are also shown for continuity.Page Break

UTILITY CAPITAL STRUCTURE
2021 DACDA IMPACTS

Line No.		2017 Actual Capital Structure Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component	2018 Actual Capital Structure Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component	2019 Actual Capital Structure Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component	2020 Actual Capital Structure Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component	2021 Actual Capital Structure Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component
		%	%	%	%	%	%	%	%	%	%	%	%	%	%	%
1.	Long-term debt	56.88	4.86	2.76	57.05	4.72	2.69	61.13	4.44	2.71	63.07	4.38	2.76	60.03	4.35	2.61
2.	Short-term debt	5.57	1.05	0.06	5.65	1.81	0.10	2.87	2.04	0.06	0.93	0.60	0.01	3.97	0.31	0.01
3.		62.45		2.82	62.70		2.80	64.00		2.77	64.00		2.77	64.00		2.62
4.	Preference shares	1.55	2.32	0.04	1.30	2.98	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.	Common equity	36.00	8.78	3.16	36.00	9.00	3.24	36.00	8.98	3.23	36.00	8.52	3.07	36.00	8.34	3.00
6.		100.00		6.02	100.00		6.07	100.00		6.01	100.00		5.84	100.00		5.63

	($ 000's)	2017	2018	2019	2020	2021
7.	Ontario Utility Income	685.0	(521.2)	(1,324.9)	(1,349.0)	(1,359.7)
8.	Rate base	259.7	5,623.8	4,283.2	2,912.8	1,542.4
9.	Indicated rate of return	263.77 %	(9.27)%	(30.93)%	(46.31)%	(88.15)%
10.	(Def.) / suff. in rate of return	257.75 %	(15.34)%	(36.94)%	(52.15)%	(93.78)%
11.	Net (def.) / suff.	669.4	(862.7)	(1,582.2)	(1,519.0)	(1,446.5)
12.	Gross (def.) / suff.	910.7	(1,173.7)	(2,152.7)	(2,066.7)	(1,968.0)

Page Break

UTILITY RATE BASE
2021 DACDA IMPACTS

($ 000's)

Line No.		2017	2018	2019	2020	2021
	Property, plant, and equipment					
1.	Cost or redetermined value	264.4	6,421.6	6,453.2	6,453.2	6,453.2
2.	Accumulated depreciation	(4.7)	(797.8)	(2,170.0)	(3,540.4)	(4,910.8)
3.		259.7	5,623.8	4,283.2	2,912.8	1,542.4
	Allowance for working capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-	-
6.	Materials and supplies	-	-	-	-	-
7.	Mortgages receivable	-	-	-	-	-
8.	Customer security deposits	-	-	-	-	-
9.	Prepaid expenses	-	-	-	-	-
10.	Gas in storage	-	-	-	-	-
11.	Working cash allowance	-	-	-	-	-
12.		-	-	-	-	-
13.	Ontario utility rate base	259.7	5,623.8	4,283.2	2,912.8	1,542.4

UTILITY INCOME
2021 DACDA IMPACTS

($ 000's)

Line No.		2017	2018	2019	2020	2021
	Revenue					
1.	Gas sales	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-
4.	Other operating revenue	-	-	-	-	-
5.	Other income	-	-	-	-	-
6.	Total revenue	-	-	-	-	-
	Costs and expenses					
7.	Gas costs	-	-	-	-	-
8.	Operation and Maintenance	-	-	-	-	-
9.	Depreciation and amortization	112.3	1,372.4	1,370.4	1,370.4	1,370.4
10.	Municipal and other taxes	-	-	-	-	-
11.	Total costs and expenses	112.3	1,372.4	1,370.4	1,370.4	1,370.4
12.	**Utility income before inc. taxes**	(112.3)	(1,372.4)	(1,370.4)	(1,370.4)	(1,370.4)
	Income taxes					
13.	Excluding interest shield	(795.4)	(809.5)	(14.1)	-	-
14.	Tax shield on interest expense	(1.9)	(41.7)	(31.4)	(21.4)	(10.7)
15.	Total income taxes	(797.3)	(851.2)	(45.5)	(21.4)	(10.7)
16.	**Ontario utility net income**	685.0	(521.2)	(1,324.9)	(1,349.0)	(1,359.7)

UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2021 DACDA IMPACTS

($ 000's)

Line No.		2017	2018	2019	2020	2021
1.	Utility income before income taxes	(112.3)	(1,372.4)	(1,370.4)	(1,370.4)	(1,370.4)
	Add Backs					
2.	Depreciation and amortization	112.3	1,372.4	1,370.4	1,370.4	1,370.4
3.	Large corporation tax	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-
6.	Total added back	112.3	1,372.4	1,370.4	1,370.4	1,370.4
7.	Sub total - pre-tax income plus add backs	-	-	-	-	-
	Deductions					
8.	Capital cost allow ance - Federal	3,001.6	3,054.9	53.2	-	-
9.	Capital cost allow ance - Provincial	3,001.6	3,054.9	53.2	-	-
10.	Items capitalized for regulatory purposes	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-
16.	Total Deductions - Federal	3,001.6	3,054.9	53.2	-	-
17.	Total Deductions - Provincial	3,001.6	3,054.9	53.2	-	-
18.	Taxable income - Federal	(3,001.6)	(3,054.9)	(53.2)	-	-
19.	Taxable income - Provincial	(3,001.6)	(3,054.9)	(53.2)	-	-
20.	Income tax provision - Federal	(450.2)	(458.2)	(8.0)	-	-
21.	Income tax provision - Provincial	(345.2)	(351.3)	(6.1)	-	-
22.	Income tax provision - combined	(795.4)	(809.5)	(14.1)	-	-
23.	Part V1.1 tax	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(795.4)	(809.5)	(14.1)	-	-
	Tax shield on interest expense					
26.	Rate base as adjusted	259.7	5,623.8	4,283.2	2,912.8	1,542.4
27.	Return component of debt	2.82%	2.80%	2.77%	2.77%	2.62%
28.	Interest expense	7.3	157.5	118.6	80.7	40.4
29.	Combined tax rate	26.500%	26.500%	26.500%	26.500%	26.500%
30.	Income tax credit	(1.9)	(41.7)	(31.4)	(21.4)	(10.7)
31.	**Total income taxes**	(797.3)	(851.2)	(45.5)	(21.4)	(10.7)

UTILITY REVENUE REQUIREMENT
2021 DACDA IMPACTS

($ 000's)

Line No.		2017	2018	2019	2020	2021
	Cost of capital					
1.	Rate base	259.7	5,623.8	4,283.2	2,912.8	1,542.4
2.	Required rate of return	6.02%	6.07%	6.01%	5.84%	5.63%
3.	Cost of capital	15.6	341.4	257.4	170.1	86.8
	Cost of service					
4.	Gas costs	-	-	-	-	-
5.	Operation and Maintenance	-	-	-	-	-
6.	Depreciation and amortization	112.3	1,372.4	1,370.4	1,370.4	1,370.4
7.	Municipal and other taxes	-	-	-	-	-
8.	Cost of service	112.3	1,372.4	1,370.4	1,370.4	1,370.4
	Misc. & Non-Op. Rev					
9.	Other operating revenue	-	-	-	-	-
10.	Other income	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-
	Income taxes on earnings					
12.	Excluding tax shield	(795.4)	(809.5)	(14.1)	-	-
13.	Tax shield provided by interest expense	(1.9)	(41.7)	(31.4)	(21.4)	(10.7)
14.	Income taxes on earnings	(797.3)	(851.2)	(45.5)	(21.4)	(10.7)
	Taxes on (def) / suff.					
15.	Gross (def.) / suff.	910.7	(1,173.7)	(2,152.7)	(2,066.7)	(1,968.0)
16.	Net (def.) / suff.	669.4	(862.7)	(1,582.2)	(1,519.0)	(1,446.5)
17.	Taxes on (def.) / suff.	(241.3)	311.0	570.5	547.7	521.5
18.	**Revenue requirement**	(910.7)	1,173.6	2,152.8	2,066.8	1,968.0
	Revenue at existing Rates					
19.	Gas sales	0.0	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.0	(0.1)	0.1	0.0	0.0
23.	Revenue at existing rates	0.0	(0.1)	0.1	0.0	0.0
24.	**Gross revenue (def.) / suff.**	910.7	(1,173.7)	(2,152.7)	(2,066.8)	(1,968.0)

ACCOUNTS WITH A ZERO BALANCE
EGD RATE ZONE

1. The following 2021 accounts for the EGD Rate Zone have no balance, and are therefore not requested for clearance to customers:
    - Gas Distribution Access Rule Impact (GDARIDA) Deferral Account
    - Electric Program Earnings Sharing (EPESDA) Deferral Account
    - Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential Variance Account
    - Open Bill Revenue (OBRVA) Variance Account
    - Ex-Franchise Third Party Billing Services (EXTPBSDA) Deferral Account
    - RNG Injection Service (RNGISVA) Variance Account

2. Consistent with past annual deferral and variance account clearance proceedings, Enbridge Gas has not listed accounts that will be reviewed through other processes in Exhibit C, Tab 1, Schedule 1, and these accounts are not addressed in this proceeding. Examples include the PGVA, DSM related accounts and Federal Carbon Charge accounts.

BREAKDOWN OF THE 2021 STORAGE AND TRANSPORTATION DEFERRAL ACCOUNT ("2021 S&TDA") - EGD RATE ZONE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Line No.	Contracted Union Capacity	Budgeted Daily Contract Demand Volume	Monthly Demand Toll Assumed in 2018 Budget	Forecasted Annual Cost (2)	Actual Daily Contract Demand Volume	Monthly Demand Toll Effective January 1, 2021 to December 31, 2021	Annual Cost (3)	Balance in the 2021 S&TDA (4)
		(GJ)	($/GJ)	($Millions)	(GJ)	($/GJ)	($Millions)	($Millions)
1.	Union Gas Dawn to Lisgar	67,929	2.865	2.3	67,929	3.110	2.5	
2.	Union Gas Dawn to Parkway	2,792,173	3.402	114.0	2,792,173	3.665	122.8	
3.	Union Gas Dawn to Parkway - M12X	200,000	4.239	10.2	200,000	4.530	10.9	
4.	Union Gas F24 T	85,000	0.069	0.1	85,000	0.073	0.1	
5.	Union Transmission Costs			126.6			136.3	(9.7)
6.	Dawn T Service Costs			(11.2)			(14.5)	3.4
7.	Federal Carbon Costs			-			0.9	(0.9)
8.	Union & Third Party Market Based Storage			20.1			22.4	(2.3)
9.	2019 Deferral Disposition - UG (1)			-			(1.6)	1.6
10.	Total			135.5			143.5	(7.9)

Notes
(1) Transporation deferral adjustments related to 2019 S&TDA reduced actual costs by $1.6M
M12 Transport ($1.6M), C1 Transport $0.003M, M16 Transport ($0.01M)
(2) Col. 1 * Col. 2 * 12
(3) Col. 4 * Col. 5 * 12
(4) Col. 3 - Col. 6

TRANSACTIONAL SERVICES REVENUE BY TYPE OF TRANSACTION ("TSDA") - EGD RATE ZONE

Line No.	Particulars	Col. 2 2017 Transactional Services Revenue ($000's)	Col. 3 2018 Transactional Services Revenue ($000's)	Col. 4 2019 Transactional Services Revenue ($000's)	Col. 5 2020 Transactional Services Revenue ($000's)	Col. 6 2021 Transactional Services Revenue ($000's)
1.	Storage Optimization	1,550.1	423.9	60.7	0.0	0.0
2.	Transportation Optimization	10,393.3	14,292.4	13,084.5	17,643.4	17,509.0
3.	Transactional Services Revenue	11,943.5	14,716.2	13,145.2	17,643.4	17,509.0
4.	Amount Included in Rates	12,000.0	12,000.0	12,000.0	12,000.0	12,000.0
5.	Less Ratepayer Portion of TS	10,749.1	13,244.6	11,830.7	15,879.1	15,758.1
6.	TSDA sub-total	1,250.9	(1,244.6)	169.3	(3,879.1)	(3,758.1)
7.	ETT Revenue - Rider H	44.5	60.1	35.1	5.8	146.1
8.	TSDA Total	1,206.4	(1,304.7)	134.3	(3,884.9)	(3,904.1)

BREAKDOWN OF THE 2021 UNACCOUNTED-FOR GAS VARIANCE ACCOUNT ("2021 UAFVA") - EGD RATE ZONE

		Col . 1	Col . 2	Col . 3	Col . 4	Col . 5	Col . 6	Col . 7	Col . 8	Col . 9	Col . 10	Col . 11	Col . 12	Col . 13
Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1.	Budget UAF (10^3m^3)	17,032.9	18,951.5	16,299.1	11,722.9	6,619.6	3,359.7	2,496.5	2,411.9	2,463.2	3,884.2	8,289.1	13,146.5	106,677.0
2.	PGVA Reference Price	161.8	161.8	161.8	166.2	166.2	166.2	160.4	160.4	160.4	199.0	199.0	199.0	
3.	Budget UAF Dollar	2,755,962.4	3,066,391.9	2,637,234.0	1,948,246.2	1,100,126.1	558,351.4	400,326.0	386,770.1	394,998.5	772,853.2	1,649,323.9	2,615,829.4	18,286,413.2
4.	Actual UAF (10^3m^3)	16,278.8	17,595.3	14,023.7	9,948.2	7,948.8	4,076.4	3,400.6	3,549.0	3,538.1	3,692.1	8,429.5	11,809.8	104,290.4
5.	UAF Annual Variance (10^3m^3) (1)	1,758.0	1,900.2	1,514.5	1,074.3	858.4	440.2	367.2	383.3	382.1	398.7	910.3	1,275.4	11,262.8
6.	Total Actual UAF (10^3m^3) (2)	18,036.9	19,495.5	15,538.1	11,022.5	8,807.3	4,516.6	3,767.8	3,932.2	3,920.2	4,090.8	9,339.9	13,085.2	115,553.2
7.	PGVA Rate	161.8	161.8	161.8	166.2	166.2	166.2	160.4	160.4	160.4	199.0	199.0	199.0	
8.	Actual UAF Dollar (3)	2,918,401.4	3,154,418.6	2,514,103.6	1,831,852.2	1,463,696.7	750,628.0	604,199.2	630,563.0	628,642.4	813,972.6	1,858,413.3	2,603,645.1	19,772,536.2
9.	UAFVA Volume Variane (4)	162,439.0	88,026.7	(123,130.4)	(116,394.0)	363,570.7	192,276.6	203,873.1	243,792.9	233,643.9	41,119.4	209,089.4	(12,184.3)	1,486,123.1
10.	Line Pack Gas (LPG) Allocation													(406,981.7)
11.	2021 Damage Adjustment													(207,750.3)
12.	2020 Company Use True-up													(117,507.2)
13.	Total 2021 UAFVA (5)													753,883.9

Notes

(1) UAF Annual Varaince Allocation	16%	17%	13%	10%	8%	4%	3%	3%	3%	4%	8%	11%	
	1,758.03	1,900.20	1,514.48	1,074.35	858.43	440.23	367.24	383.27	382.10	398.73	910.35	1,275.40	11,262.80

(2) Line 4 + Line 5
(3) Line 6 * Line 7
(4) Line 8 - Line 3
(5) Line 9 + Line 10 + Line 11 + Line 12

2021 AVERAGE USE TRUE UP VARIANCE ACCOUNT - EGD RATE ZONE

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
Rate Class	Budget Annual Use	Normalized Actual Annual Use	Normalized Usage Variance (1)	Budget Customer Meters	Normalized Volumetric Variance (2)	DSM Budget	DSM Actual	DSM Volumetric Variance (3)	Normalized Volumetric Variance Excluding DSM (4)	Unit Rate	AUTUVA: Revenue Impact, Exclusive of Gas Costs (5)
	(m^3)	(m^3)	(m^3)		(10^6m^3)	(10^6m^3)	(10^6m^3)	(10^6m^3)	(10^6m^3)	($/$m^3$)	($Millions)
1	2,452	2,404	(48)	2,088,486	(99.4)	(4.8)	(4.8)	0.0	(99.4)	0.0712	(7.07)
6	28,889	27,794	(1,094)	170,204	(186.3)	(10.8)	(10.8)	0.0	(186.3)	0.0422	(7.86)
Total											(14.93)

Notes
(1) Col. 2 - Col. 1
(2) Col. 3 * Col. 4
(3) Col. 7 - Col. 6
(4) Col. 5 - Col. 8
(5) Col. 9 * Col. 10

Enbridge Gas Inc.
50 Keil Drive N
Chatham, Ontario N7M 5M1
Canada

January 4, 2021

Subject: Storage at Dawn, injections commencing April 1, 2021

Enbridge Gas Inc. operating as Enbridge Gas Distribution (Enbridge Gas) requires firm natural gas storage services with injections commencing April 1, 2021.

This storage service request is being administered by Guidehouse (formerly Navigant Consulting) on behalf of Enbridge Gas.

All questions and responses are to be directed to paul.moran@navigant.com. Due to the recent acquisition of Navigant Consulting by Guidehouse, we will continue to use the Navigant.com domain for purposes of this RFP. Do not contact Enbridge Gas directly regarding this process.

Enbridge Gas is seeking a diverse portfolio of storage services that both meet and exceed the minimum requirements below. This includes those that allow higher deliverability and access to multiple nomination windows for each gas day.

Enbridge Gas requires that these storage services meet the following specifications:

Term: Up to five (5) years commencing April 1, 2021. To encourage storage contracts term diversity, Enbridge Gas is seeking service offerings of various term lengths. The amount placed will be at Enbridge Gas's discretion.

Term	Potential to be contracted
1 - year	0 PJ's
2 - year	0 - 1 PJ's
3 - year	0 - 2 PJ's
4 - year	0 - 2 PJ's
5 - year	0 - 3 PJ's

Location: Enbridge Gas will deliver gas to Storage Provider at Union Dawn for injection, and Storage Provider will re-deliver gas to Enbridge Gas at Union Dawn for withdrawal. If any transportation capacity is included as part of the storage offering to facilitate Dawn injections and withdrawals, please provide details.

Firm Injection Requirements: Must include the months from May 1 through Sept. 30

Firm Withdrawal Schedule: Must include the months from Dec. 1 through March 31

Responses: Should you be interested in supplying this storage service to Enbridge Gas, please complete the attached Excel form, stating the delivery points, term, MSB and service attributes with the relevant pricing, including demand, commodity charges and other items indicated.[1]

The deadline to submit your proposal(s) is **2 p.m. Mountain Daylight Time on Jan. 25, 2021,** after which time Enbridge Gas will contact the parties which submitted proposals that have been selected[2]. Please submit your proposal(s) to the attention of Paul Moran per the instructions in the enclosed attachment.

Additional Information: Enbridge Gas invites all potential participants to review a presentation that has been posted in the Storage and Transportation section of its website, within Presentations.

If you have questions regarding this RFP, please direct to the attention of Paul Moran at the email address provided above. The deadline for any ***queries*** *is 12 p.m.(noon) Mountain Daylight Time on Jan. 12, 2021. All queries and responses will be provided to all parties on Jan. 15, 2021.*

Enbridge Gas will contact successful bidders following the close of the RFP process.

Yours truly,
Paul Moran
Guidehouse

[1] This storage service request may have Dodd Frank Act implications and may require specific clauses to be included in any storage agreement between the parties. Any such storage agreement will not be binding until a definitive agreement is executed by the parties.

[2] Please note that successful suppliers must meet all of Enbridge's credit criteria. Enbridge, in its sole discretion and for whatever reason, may accept or reject any and all proposals. Enbridge reserves the right at any time after the deadline to conduct negotiations with one or more of the bidders to the exclusion of others, and such negotiations may include changes to the storage service described in this letter.

Number	Respondent	Term (Years)	Amount (GJs)	Withdrawal Period			Withdrawal Ratchet		Ratchet Score	Price				Annual Price
		Term (Years)	Amount (GJs)	start	End	Days	max Daily withdrawal	ratchet (minimum days to withdraw)	Ratchet Score	Annual Demand	Variable Injection	Variable Withdrawal	Annual Price per 1 PJ	Annual Price for Provided Volume
[redacted]														

UNABSORBED DEMAND COSTS (UDC) VARIANCE ACCOUNT
UNION RATE ZONES

1. The balance in the UDC Variance Account is a credit to ratepayers of $1.666 million plus interest as of December 31, 2022 of $0.028 million, for a total of $1.694 million. The $1.666 million balance is the difference between the actual UDC incurred by the Union Rate Zones and the amount of UDC collected in rates.

1. UDC Recovery in Rates

2. To meet customer demands across the Union rate zones and to meet the planned storage inventory levels at October 31, approved rates for the Union rate zones in 2021 included planned unutilized pipeline capacity of 11.3 PJ in Union North West, 3.1 PJ in Union North East and 0 PJ in Union South. The UDC volumes included in 2021 rates are based on the Gas Supply Plan filed in Union's Dawn Reference Price proceeding[1].

3. As discussed in the Enbridge Gas 5 Year Gas Supply Plan[2], in Union North, the upstream transportation capacity (long-haul, short-haul and STS) is first sized to meet the design day requirements. The amount of transportation capacity needed to meet average annual demand requirements is less than the capacity required to meet design day requirements. Therefore, a portion of contracted capacity for the Union rate zones is planned to be unutilized. In a warmer than normal year, UDC may be incurred in Union South, and additional UDC in Union North, to balance supply with lower demands. The Union North and Union South transportation portfolios are managed on an integrated basis and the pipeline to leave unutilized, if necessary, is determined based on the least cost option. In the EB-2021-0149

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[1] EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 1.
[2] EB-2019-0137, page 82.

Settlement Proposal related to the disposition of the 2020 UDC Variance account, Enbridge Gas agreed:

"In future deferral and variance account clearance applications related to the deferred rebasing term, Enbridge Gas agrees that it will include evidence reporting on: UDC and transportation capacity released by rate zone, and the costs and revenues transferred between rate zones.[3]"

Table 1 provides the capacity released by rate zone and the associated UDC costs and/or revenue. The path released does not determine where the UDC costs or associated revenue for the releases will be allocated. Instead, the costs and revenue are allocated based on the portion of the UDC variance driven by each respective rate zone, as can be seen in Table 2.

Table 1
Capacity Released & Related Costs Incurred

Line No.	Particulars	Union North East	Union North West	Union South	Total Franchise Area
1	Capacity Released (TJ)	2,953	5,957	19,631	28,541
2	UDC Costs Incurred ($000's)	1,522	3,754	3,040	8,315
3	Released UDC Capacity ($000's)	0	(1,238)	(123)	(1,361)

4. Enbridge Gas collected $8.620 million in rates for UDC for the Union rate zones during 2021 and recorded an associated interest credit of $0.028 million (see Table 2). Actual UDC costs in 2021 were $8.315 million offset by $1.361 million in released capacity value, resulting in a net cost of $6.954 million (see Table 3).

[3] EB-2021-0149, Exhibit N1, Tab 1, Schedule 1, page 15.

Actual UDC costs are allocated to Union North West, Union North East and Union South in proportion to the actual supply and demand variances which occurred in each respective area.

5. The variance between the amounts collected in rates and the actual UDC costs, including the interest credit of $0.028 million, results in a net credit to ratepayers in the UDC Variance Account of $1.694 million.

6. The balance applicable to sales service and bundled DP customers in Union North West is a credit of $4.806 million and in Union North East, a credit of $0.033 million. There is a debit of $3.145 million applicable to sales service customers in Union South.

7. Table 2 provides the derivation of the UDC variance account balances by operational area.

Table 2
UDC Variance Account by Operational Area

Line No.	Particulars ($000's)	Union North East	Union North West	Union South	Total Franchise Area
1	UDC Collected in Rates	(1,511)	(7,109)	-	(8,620)
2	UDC Costs Incurred (Table 3)	1,479	2,383	3,092	6,954
3	Variance (line 1 + line 2)	(32)	(4,726)	3,092	(1,666)
4	Interest	(1)	(80)	53	(28)
5	(Credit)/Debit to Operations Area	(33)	(4,806)	3,145	(1,694)

A description of each item in Table 2 is set out below:

1.1 UDC Collected in Rates

8. The 2021 OEB-approved rates include $9.082 million of UDC associated with 14.4 PJ of planned unutilized pipeline capacity in Union North West and Union North East and no planned unutilized pipeline capacity in Union South. The total cost of UDC in rates assumes TC Energy final tolls effective January 1, 2021. On an actual basis in 2021, Enbridge Gas recovered $8.620 million in Union North West and Union North East and $0.0 million in Union South.

1.2 UDC Costs Incurred

9. The actual unutilized capacity in 2021 was 28.5 PJ. The level of unutilized capacity experienced in 2021 was largely due to planned unutilized capacity (and resulting UDC) and warmer than normal weather.

10. The costs reflected in the UDC Variance Account are the total demand charges for unutilized pipeline capacity totaling $8.315 million, partially offset, by the value of $1.361 million generated from releasing the pipeline transportation capacity to the market. Unutilized upstream transportation capacity is released and sold on the secondary market to minimize UDC. The value generated from the transportation releases is credited to the UDC Variance Account mitigating the overall UDC impact as shown in Table 3 below.

Table 3

UDC Costs Incurred

Line No.	Particulars ($000's)	Union North East	Union North West	Union South	Total Franchise Area
1	UDC Costs Incurred	1,768	2,849	3,697	8,315
2	Released Capacity Revenue	(289)	(466)	(605)	(1,361)
3	Net UDC Costs (Credit)/Debit	1,479	2,383	3,092	6,954

ACCOUNT NO. 179-131 UPSTREAM TRANSPORTATION OPTIMIZATION – UNION RATE ZONES

1. The Upstream Transportation Optimization Deferral Account was approved by the OEB in its EB-2011-0210 Decision to capture the variance between the ratepayers' 90% share of actual net revenues from optimization activities, and the amount refunded to ratepayers in rates. The 2021 balance in this deferral account is a debit from ratepayers of $8.616 million plus interest of $.078 million for a total debit from ratepayers of $8.694 million.

2. In setting rates for 2021, the OEB approved a forecast of optimization revenue of $14.918 million. Of that amount, 90% or $13.426 million, was credited to ratepayers in the OEB-approved 2021 rates.[1] On an actual basis, consistent with the method approved in its EB-2011-0210 Decision and Rate Order, Union credited $15.392 million in rates to ratepayers during 2021, $1.966 million greater than the OEB-approved amount of $13.426 million. The credit is due to actual sales service volumes exceeding the forecast sales service volumes in rates. The main driver of actual sales service volumes exceeding the forecasted amount is customer growth since 2013.

3. The Company earned $7.529 million in net revenues from upstream transportation optimization during 2021 in the Union Rate Zones. In accordance with the OEB-approved sharing methodology, 90% of this net revenue, or $6.776 million, is to be credited to customers. As stated above, $15.392 million has already been credited through rates; therefore, the deferral balance is a debit from ratepayers of $8.616 million ($15.392 million less $6.776 million).

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[1] Detailed schedule last filed at EB-2017-0087 (2018 Rates), Draft Rate Order, Working Papers, Schedule 14, page 1. The credit of $13.426 million to Union rate zone in-franchise customers is maintained in the setting of rates for the 2019-2023 deferred rebasing period in accordance with the approved rate-setting mechanism.

4. Exhibit E, Tab 1, Schedule 1, provides a summary of the calculation of the balance in this deferral account. 2021 actual Upstream Transportation Optimization revenue in the Union rate zones is lower than 2013 OEB-approved revenue primarily due to the elimination of the TransCanada FT-RAM program ($5.800 million) and changing market dynamics.

ACCOUNT NO. 179-70 SHORT-TERM STORAGE AND OTHER BALANCING SERVICES – UNION RATE ZONES

1. The Short-Term Storage and Other Balancing Services Deferral Account includes revenues from C1 Off-Peak Storage, Gas Loans, Supplemental Balancing Services and C1 Short-Term Firm Peak Storage. The deferral account compares the ratepayer share (90%) of net revenue for Short-Term Storage and Other Balancing Services with the amount credited to ratepayers in rates for Short-Term Storage and Other Balancing Services. The net revenue for Short-Term Storage and Other Balancing Services is determined by deducting the costs incurred to provide service from the gross revenue. The balance in this deferral account is a debit from ratepayers of $3.577 million, plus interest of $0.0325 million for a total debit from ratepayers of $3.609 million.

2. As shown in Table 3, the balance is calculated by comparing $0.974 million (ratepayer 90% share of the actual 2021 Short-Term Storage and Other Balancing Services net revenue of $1.082 million) to the net revenue included in Union rate zone rates of $4.551 million.[1] The details of the balance are found at Exhibit E, Tab 1, Schedule 2.

[1] EB-2011-0210, Decision and Rate Order, January 17, 2013, page 16.

Table 3

Deferral Summary: Short-term Storage and Other Storage Services

Line No.	Particulars ($000's)	Actual 2021
1	Net Revenue	1,082
2	Ratepayer Portion (90%)	974
3	Approved in Rates	4,551
4	Deferral Balance Payable to/(Collectable from) Ratepayers	(3,577)

3. Actual 2021 revenues from C1 Off-Peak Storage, Gas Loans and all other Balancing services of $1.075 million were $1.425 million lower than the 2013 OEB-approved forecast of $2.500 million.

4. The C1 Short-Term Firm Peak Storage revenues of $1.536 million were $6.347 million lower than the 2013 Board-approved forecast of $7.883 million. Actual Union rate zone utility storage requirements for 2021 were 8.3 PJ higher than the 2013 OEB-approved forecast, resulting in a decrease in the C1 Short-Term Firm Peak Storage available for sale (from 11.3 PJ in 2013 OEB-approved to 3.0 PJ in 2021). Union rate zone customers received the value of storage directly through the use of the storage space, rather than through the sale of short-term storage.

5. Year-over-year, actual utility storage requirements for 2021 were 0.7 PJ lower than the requirement in 2020, resulting in an increase in the C1 Short-Term Peak Storage available for sale (from 2.3 PJ in 2020 to 3.0 PJ in 2021). This is a result of a decrease in the storage requirement for utility customers. The storage requirement for the general service market was calculated using the OEB-approved aggregate excess methodology. The storage requirement for the contract market was calculated specifically for each customer using either the OEB-approved aggregate excess

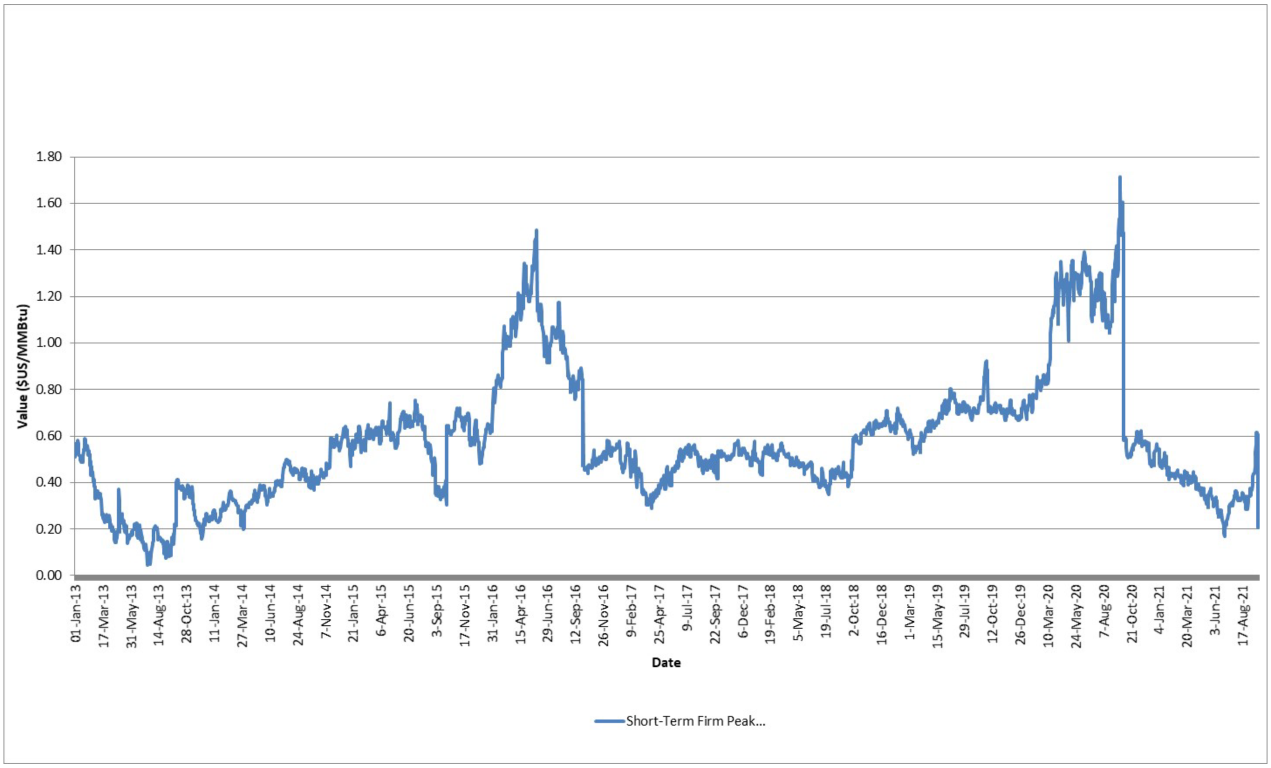
methodology, the 15 times obligated Daily Contracted Quantity (DCQ) storage methodology, or the 10 times Firm Contract Demand (CD) storage methodology (for those customers who have elected the Customer Managed Service).[2] Enbridge Gas has included the calculation for utility storage space requirements and the deliverability by rate class at Exhibit E, Tab 1, Schedule 2, Appendix A.[3]

6. The 2013 OEB-approved forecast implied an annual average value for C1 Short-Term Firm Peak Storage of $0.70/GJ ($7.883 million/11.3 PJ), and the actual average annual C1 Short-Term Firm Peak Storage value in 2021 was $0.51/GJ ($1.5 million/3.0 PJ). Please see Figure 1 for Short-Term Peak Storage values in US dollars.

[2] EB-2016-0245, Decision and Rate Order, Schedule 1, Settlement Proposal, page 7.
[3] EB-2021-0149, Decision on Settlement Proposal, Schedule 1, Settlement Proposal, page16.

Figure 1

Historical Short-Term Firm Peak Storage Values at Dawn 2013-2021



1. Non-Utility Storage Balances for 2021

7. In its EB-2011-0210 Decision, the OEB directed legacy Union to file a report similar to that ordered in EB-2011-0038 to monitor the inventory related to non-utility storage operations. Exhibit E, Tab 1, Schedule 3 shows the non-utility inventory balances for October and November of 2021 (for legacy Union storage).

8. During the 2021 injection season, the non-utility storage balance peaked on November 18, 2021 at 98.9% full with a balance of 126.1 PJ compared to available space of 127.6 PJ. At October 31, 2021, the date to which the Company manages its storage balance, the non-utility balance was 95.1% of available space. The balance stayed below the total non-utility available space of 100% for the rest of 2021.

9. In EB-2011-0210, the OEB further ordered Union to file a calculation for a storage encroachment payment from Union's non-utility business to Union's utility business, if Union's non-utility business encroached on Union's utility space. There was no encroachment of utility space in 2021 and therefore no calculation applies.

<u>2. Sale of Non-Utility Storage Space</u>

10. Enbridge Gas prioritizes the sale of its legacy Union utility storage ahead of the sale of its short-term non-utility storage and allocates short-term peak storage margins between utility and non-utility as directed by the OEB in EB-2011-0210.[4] Margins from short-term peak storage services are proportionately split between the utility and non-utility customers based on the utility and non-utility share of the total quantity of short-term peak storage sold each calendar year. Short-term peak sales include any sale of storage space for a term of less than two storage years.

11. In 2021, Enbridge Gas sold a total of 3.0 PJ of short-term peak storage (legacy Union). The total 3.0 PJ was excess utility space, calculated by deducting 97.0 PJ of in-franchise utility requirement (as per the Gas Supply Plan) from the total 100 PJ of in-franchise utility storage. There was no sale of short-term peak storage from non-utility space. Total revenue from the sale of C1 Short-Term Peak Storage (Utility) in 2021 was $1.536 million. Details of the above sales are reflected in Exhibit E, Tab 1, Schedule 4.

[4] EB-2011-0210, Decision and Order, pages 116-117.

ACCOUNT NO. 179-133 NORMALIZED AVERAGE CONSUMPTION (NAC)
UNION RATE ZONES

1. The purpose of the NAC deferral account is to record the variance in delivery revenue and storage revenue and costs resulting from the difference between the target NAC included in OEB-approved rates and the actual NAC for general service rate classes Rate M1, Rate M2, Rate 01 and Rate 10. As described in Union's 2014 Deferral Account Disposition[1] proceeding, including the revenue from storage rates in the NAC deferral account requires storage-related costs associated with the difference in target and actual NAC to also be included in the deferral account balance.

2. For 2021, the balance in the NAC deferral account is a debit to ratepayers of $18.998 million plus interest of $0.239 million for a total debit to ratepayers of $19.237 million.

3. The NAC Deferral Account follows the same methodology agreed to by parties in Union's 2014-2018 Incentive Regulation (IR) Settlement Agreement[2] and as subsequently modified in Union's 2015 Rates[3] proceeding.

1. Target and Actual NAC

4. The 2021 target NAC used to calculate base rates for each rate class was approved by the OEB in Enbridge Gas's 2021 Rates[4] proceeding. The 2019 actual NAC, weather normalized using the 2021 weather normal, was used to determine the 2021 target NAC for each rate class to calculate base rates. Setting the 2021 target

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[1] EB-2015-0010.
[2] EB-2013-0202.
[3] EB-2014-0271.
[4] EB-2020-0095.

NAC based on the 2019 actual NAC recognizes that over the two-year span to the current year, any volumes saved and lost revenues due to DSM activities will be captured by the variance between the target NAC and actual NAC. This is due to the inclusion of the DSM saved volumes within the actual reported consumption.

5. The 2021 forecast usage used to calculate Y factor unit rates for each rate class was approved by the OEB in Enbridge Gas's 2021 Rates proceeding. The unit rates for pass-through (Y factor) costs are derived based on OEB-approved cost allocation and rate design methodologies and are passed through to customers at cost.

6. The 2021 actual NAC for each rate class is weather normalized using the 2021 weather normal, which is produced using the OEB-approved weather methodology consisting of a 50:50 average of the 30-year average and the 20-year trend estimates of annual heating degree-days.

7. Table 1 provides the 2021 target NAC and 2021 actual NAC by rate class for base rates.

Table 1
2021 Target and Actual NAC - Base Rates

Line No.	Particulars (m^3/customer)	Rate 01	Rate 10	Rate M1	Rate M2
		(a)	(b)	(c)	(d)
1	2021 Target NAC	2,889	171,540	2,776	168,419
2	2021 Actual NAC	2,766	151,411	2,668	149,840
3	Variance (Target - Actual NAC)	124	20,129	108	18,580

8. Table 2 provides the 2021 target and 2021 actual NAC by rate class for Y factor rates.

Table 2
2021 Target and Actual NAC - Y Factor Rates

Line No.	Particulars (m^3/customer)	Rate 01	Rate 10	Rate M1	Rate M2
		(a)	(b)	(c)	(d)
1	2021 Target NAC	2,830	166,842	2,692	169,477
2	2021 Actual NAC	2,766	151,411	2,668	149,840
3	Variance (Target - Actual NAC)	64	15,431	24	19,637

2. Delivery and Storage Revenues

9. The deferral account balance is calculated by multiplying the variance between the weather normalized target NAC and the weather normalized actual NAC by the 2013 OEB-approved number of customers and the 2021 OEB-approved delivery and storage rates for each general service rate class. A credit balance in the NAC Deferral Account reflects that the actual NAC is greater than the target NAC, while a debit balance in the NAC Deferral Account reflects that the actual NAC is less than the target NAC.

10. Table 3 provides the NAC Deferral Account balances by rate class. The detailed calculation of the NAC Deferral Account balance can be found at Exhibit E, Tab 1, Schedule 6.

Table 3
2021 NAC Deferral Account

Line No.	Particulars ($000s)	Rate 01	Rate 10	Rate M1	Rate M2	Total
		(a)	(b)	(c)	(d)	(e)
1	Delivery Revenue Balances	3,594	2,444	4,539	5,779	16,355
2	Storage Revenue Balances	1,873	1,407	916	886	5,081
3	Storage Cost Balances	(201)	(99)	(890)	(1,249)	(2,438)
4	Interest	64	45	65	65	239
5	Total NAC Deferral Balance	5,330	3,797	4,629	5,481	19,237

3. Deferral Account Impacts

11. For Rate M1, the 2021 actual NAC is lower than the target NAC used to derive base rates by 108 m^3/customer (Table 1, line 3, column (c)) and lower than the target NAC used to derive Y factor rates by 24 m^3/customer (Table 2, line 3, column (c)). As shown in Table 3 above, this results in a delivery and storage revenue debit to ratepayers of $5.454 million ($4.539 million and $0.916 million respectively). In addition, the NAC volume variance decreases the Rate M1 storage requirement by 1.310 PJ. Accordingly, EGI must refund an amount of $0.890 million (Table 3, line 3, column (c)) to Rate M1 customers to recognize the decreased Rate M1 storage requirements.

12. For Rate M2, the 2021 actual NAC is lower than the target NAC used to derive base rates by 18,580 m^3/customer (Table 1, line 3, column (d)) and lower than the target NAC used to derive Y factor rates by 19,637 m^3/customer (Table 2, line 3, column (d)). As shown in Table 3 above, this results in a delivery and storage revenue debit to ratepayers of $6.665 million ($5.779 million and $0.886 million

respectively). In addition, the NAC volume variance decreases the Rate M2 storage requirement by 1.840 PJ. Accordingly, EGI must refund $1.249 million (Table 3, line 3, column (d)) to Rate M2 customers to recognize the decreased Rate M2 storage requirements.

13. For Rate 01, the 2021 actual NAC is lower than the target NAC used to derive base rates by 124 m^3/customer (Table 1, line 3, column (a)) and lower than the target NAC used to derive Y factor rates by 64 m^3/customer (Table 2, line 3, column (a)). As shown in Table 3 above, this results in a delivery and storage revenue debit to ratepayers of $5.467 million ($3.594 million and $1.873 million respectively). In addition, the NAC volume variance decreased the Rate 01 storage requirement by 0.240 PJ. Accordingly, EGI must refund an amount of $0.201 million (Table 3, line 3, column (a)) to Rate 01 customers to recognize the decreased Rate 01 storage requirements.

14. For Rate 10, the 2021 actual NAC is lower than the target used to derive base rates NAC by 20,129 m^3/customer (Table 1, line 3, column (b)) and lower than the target NAC used to derive Y factor rates by 15,431 m^3/customer (Table 2, line 3, column (b)). As shown in Table 3 above, this results in a delivery and storage revenue debit to ratepayers of $3.851 million ($2.444 million and $1.407 million respectively). In addition, the NAC volume variance decreases the Rate 10 storage requirement by 0.120 PJ. Accordingly, EGI must refund $0.099 million (Table 3, line 3, column (b)) to Rate 10 customers to recognize the decreased Rate 10 storage requirements.

4. Storage Costs

15. The storage costs recognize that variances between the 2021 target NAC and the 2013 OEB-approved NAC change the storage requirements for each general service rate class. As OEB-approved storage rates are not updated during the IR term to reflect changes in storage requirements due to NAC variances, EGI must capture

the NAC-related change in storage costs in the NAC Deferral Account for the Union rate zones as per the OEB's Decision in Union's 2013 Deferrals Disposition proceeding (EB-2014-0145), page. 9, "starting in 2014, the NAC Deferral Account, which replaces the Average Use Per Customer Deferral Account, will include storage related revenues and costs for general service rate classes."

16. To determine the change in storage requirements for each general service rate class due to NAC variances, the Company calculated the NAC volume variance per customer between its 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes multiplied by the 2013 OEB-approved number of customers.

17. Using the OEB-approved aggregate excess methodology, EGI calculated the change in storage requirements for each of the general service rate classes due to variances in NAC. The 2021/2022 Gas Supply Plan volumes represent the April 1, 2021 to March 31, 2022 period, which are used to determine the storage requirements for general service rate classes effective November 1, 2021. These general service rate class storage requirements are then used in the calculation of the total in-franchise utility storage space requirement at November 1, 2021. The difference between the total in-franchise utility storage requirement and the total 100 PJ of utility storage represents the excess utility storage capacity available for sale (excess utility space) at November 1, 2021.

18. For Rate M1, the NAC volume variance between the 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes was a decrease of 6.254 PJ. The majority of the NAC volume variance decrease occurred in the winter months, which decreased the Rate M1 storage requirement by 1.310 PJ. This resulted in decreased storage costs of $0.890 million (Table 3, line 3, column (c)).

19. For Rate M2, the NAC volume variance between the 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes was an increase of 4.705 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate M2 storage requirement by 1.840 PJ and resulted in decreased storage costs of $1.249 million (Table 3, line 3, column (d)).

20. For Rate 01, the NAC volume variance between the 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes was an increase of 0.164 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate 01 storage requirement by 0.240 PJ and decreased storage costs by $0.201 million (Table 3, line 3, column (a)).

21. For Rate 10, the NAC volume variance between the 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes was an increase of 0.543 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate 10 storage requirement by 0.120 PJ and resulted in decreased storage costs of $0.099 million (Table 3, line 3, column (b)).

22. Overall, the NAC volume variance between the 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes resulted in a decrease in general service storage requirements of 3.510 PJ. Accordingly, EGI has included a storage cost credit of $2.438 million in the NAC Deferral Account. Please see Table 4 below for a summary of the change in general service storage requirements due to NAC volume variances by rate class.

Table 4

Change in General Service Storage Requirements from 2013 OEB-approved (based on weather normalized NAC)

	PJ		PJ
Rate M1	(1.310)	Rate 01	(0.240)
Rate M2	(1.840)	Rate 10	(0.120)
Total South	(3.150)	Total North	(0.360)

23. The reduction in storage activity has decreased storage deliverability costs, the commodity-related costs at Dawn and storage inventory carrying costs.

24. The 3.510 PJ reduction in general service storage requirements due to NAC volume variances forms part of the 2.984 PJ of excess utility space available for sale for winter 2021/2022. The revenue from the sale of the 2.984 PJ of excess utility space is recorded in the Short-Term Storage and Other Balancing Deferral Account (Account No. 179-70).

DEFERRAL CLEARING VARIANCE ACCOUNT– UNION RATE ZONES

1. The purpose of the Deferral Clearing Variance Account (DCVA) is to capture the differences between the forecast and actual volumes associated with the disposition of deferral account balances to the Union rate zones. The intent of the variance account is to minimize or eliminate the gains or losses to ratepayers and the Company as a result of volume variances associated with the disposition of deferral account balances.

2. The balance in this variance account is a credit to Union rate zones ratepayers of $3.120 million, plus interest to December 31, 2022 of a $0.046 million, for a total credit of $3.166 million. The balance includes the following residual balances from various dispositions, discussed further below:

	($ millions)
a. Prospective Recovery Account Dispositions	
i. 2017/18 Demand Side Management (DSM)	(1.990)
ii. 2019 Earnings Sharing and Deferrals	(1.982)
iii. 2019 Federal Carbon Pricing Program (FCPP)	(0.291)
b. One-time Adjustment Account Dispositions	
i. 2019 DSM	1.122

3. As reflected in Exhibit E, Tab 1, Schedule 2, page 1, Line 5, the overall balance also reflects a debit of $0.020 million in relation to the various deferral account dispositions including residual amounts not able to be disposed of as one-time billings and amounts related to manual rebills.

<u>1. Prospective Recovery Account Dispositions</u>

6. Of the account balance, a $3.971 million credit balance, plus interest of $0.589 credit, represents an under-refund/over-collection from ratepayers for dispositions disposed of using prospective recovery in the 2017/18 DSM Deferrals Disposition[1] and 2019 Earnings Sharing and Deferrals Disposition[2] proceedings. Please see Exhibit E, Tab 1, Schedule 5, page 1 for a summary of the deferral account balance disposed of using the prospective recovery method. Additionally, a $0.291 million credit is a residual balance from the disposition of 2019 federal carbon balances in the 2020 FCPP[3] proceeding.

<u>1.1Union Rate Zones 2017-2018 DSM Deferral (EB-2020-0067)</u>

7. In its EB-2020-0067 Decision, the OEB approved the prospective disposition of the balances in the approved deferral accounts to rate classes through a temporary rate adjustment from April 1, 2021 to June 30, 2021. The total amount approved for prospective recovery from rate classes was a $24.196 million debit. Please see Exhibit E, Tab 1, Schedule 5, page 2, column (f), for the forecast amount to be recovered by rate class, based on the forecasted volumes as noted in column (a) of the same exhibit.

8. Actual volumes for the period April 1, 2021 to June 30, 2021 averaged approximately 4% greater than forecast due to colder weather in the same period. As a result of the actual volumes being greater than the forecasted volumes, the Company recovered $26.186 million, which is $1.990 million more than the balance approved for disposition. Please see Exhibit E, Tab 1, Schedule 5, page 2, column (g) for the actual disposition of deferral accounts and column (h) of the same exhibit for the variance between forecast and actual disposition.

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[1] EB-2020-0067.
[2] EB-2020-0134.
[3] EB-2019-0247.

1.2 Union Rate Zones 2019 Earnings Sharing and Deferrals Disposition (EB-2020-0134)

9. In its EB-2020-0134 Decision, the OEB approved the prospective disposition of the balances in the approved deferral accounts to rate classes through a temporary rate adjustment from October 1, 2021 to December 31, 2021. The total amount approved for prospective refund to rate classes was a $14.096 million credit. Please see Exhibit E, Tab 1, Schedule 5, page 3, column (e), for the forecast amount to be refunded by rate class, based on the forecasted volumes as noted in column (a) of the same exhibit.

10. Actual volumes for the period October 1, 2021 to December 31, 2021 averaged approximately 19% lower than forecast primarily due to warmer weather in the same period. As a result of the actual volumes being lower than the forecasted volumes, the Company refunded $12.115 million, which is $1.982 million less than the balance approved for disposition. Please see Exhibit E, Tab 1, Schedule 5, page 3, column (f) for the actual disposition amounts by rate class, based on the actual volumes as shown in column (b). Column (g) of the same exhibit shows the variance between forecast and actual disposition.

1.3 Union Rate Zones 2020 Federal Carbon Pricing Program (EB-2019-0247)

5. A $0.291 million credit balance pertains to over-collection from ratepayers related to the 2019 FCPP deferral and variance account disposition within the 2020 FCPP proceeding. In its EB-2019-0247 Decision, the OEB approved the prospective disposition of the balances in the 2019 FCPP deferral accounts to rate classes through a temporary rate adjustment from October 1, 2020 to December 31, 2020.

6. Following the OEB’s approval of 2019 balances, contract customers were subsequently exempted from the customer-related federal carbon levy. Enbridge Gas had already received approval to collect amounts from Union rate zones

customers related to the exempted customers, therefore, the over-collection from customers requires a disposition to ratepayers.

2. One-time Adjustment Account Disposition

11. The 2019 DSM Deferrals Disposition was the first time Enbridge Gas used a common disposition methodology across the EGD and Union rate zones. The Rate Order of that proceeding reflects a one-time billing adjustment for all Enbridge Gas customers.

2.1 Union Rate Zones 2019 DSM Deferrals (EB-2021-0072)

12. A $1.122 million debit balance represents an under-collection from ratepayers for disposition using one-time-adjustment in the 2019 DSM Deferrals Disposition[4] proceeding. In July of 2021, the Company received approval to clear the 2019 DSM deferral accounts within the EB-2021-0072 proceeding and dispose of the balance in October 2021. The billing adjustment was derived for each customer individually by applying the disposition unit rates to each customer's actual consumption volume for the period July 1, 2019 to June 30, 2020 for the Union rate zone general service customers.[5] The outstanding amount is as a result of the billing systems' inability to locate all the intended customers.

[4] EB-2021-0072.
[5] Enbridge Gas Draft Rate Order, EB-2021-0072, June 30, 2021.

PARKWAY WEST PROJECT COSTS DEFERRAL ACCOUNT – UNION RATE ZONES

1. In its Parkway West Project (EB-2012-0433) Decision, the OEB approved the establishment of the Parkway West Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Parkway West Project and the revenue requirement included in rates.

2. The balance in this deferral account is a credit to Union rate zones ratepayers of \$0.603 million plus interest of \$0.006 million for a total credit balance of \$0.609 million. The balance of \$0.603 million represents the difference between the revenue requirement of \$19.971 million included in 2021 rates (EB-2020-0095) and the calculation of the actual revenue requirement for 2021 of \$19.368 million as shown in Table 1.

TABLE 1
2021 PARKWAY WEST PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2021 Board-approved (a)	Col. 2 2021 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	15	15
2.	Cumulative Capital Expenditures	233,147	231,703	(1,444)
3.	Average Investment	199,738	198,371	(1,367)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	2,206	1,871	(335)
5.	Depreciation Expense (1)	5,532	5,496	(36)
6.	Property Taxes	579	388	(191)
7.	Total Operating Expenses	8,317	7,755	(562)
8.	Required Return (2)	11,304	11,227	(77)
9.	Total Operating Expense and Return	19,621	18,982	(639)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	2,315	2,299	(16)
11.	Income Taxes - Utility Timing Differences (4)	(1,966)	(1,914)	52
12.	Total Income Taxes	350	385	35
13.	Total Revenue Requirement	19,971	19,368	(603)

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.82% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
$198.326 million * 64% * 3.82% = $4.849 million plus
$198.326 million * 36% * 8.93% = $6.376 million for a total of $11.225 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Capital Expenditures

3. The actual 2021 capital expenditures on in-service assets are $0.015 million higher than 2021 OEB-approved as shown in Table 2.

TABLE 2
PARKWAY WEST CAPITAL EXPENDITURES

Line No.	Particulars ($000's)	2021 Board-approved (a)	2021 Actuals (b)	Difference (c) = (b - a)
1.	Plant Infrastructure	-	15	15
2.	Compressor Equipment	-	-	-
3.	Total Capital Expenditures	-	15	15

4. Plant infrastructure costs were $0.015 million higher than costs included in 2021 OEB-approved rates due to consulting fees regarding the heritage homes discussed in the Company's 2019 Earnings Sharing and Deferrals Disposition interrogatory response to OEB staff[1]. Enbridge Gas plans to mothball the heritage homes in 2022.

2. Average Investment

5. The average investment decrease of $1.367 million from OEB-approved is due to the cumulative capital expenditures being $1.444 million lower than OEB-approved.

3. Operating Expenses

6. Operating and maintenance expenses were $0.335 million below the costs included in the 2021 OEB-approved rates. The decrease is a result of a Long-term Service Agreement (LTSA) that was included in 2021 OEB-approved rates but not incurred in actual O&M expense. The Company elected not to enter an LTSA, that would

[1] EB-2020-0134, EGI 2019 Earnings Sharing and Deferrals Disposition, Exhibit I.STAFF.25, a).

have provided loss of critical unit coverage should the Company experience operational issues with Parkway B, as with the commissioning of Parkway D it was determined that it provided the required backup.

7. Property taxes were $0.191 million lower than costs included in 2021 OEB-approved rates. The decrease is a result of the Municipal Property Assessment Corporation (MPAC) deciding not to apply a Land Classification tax charge that was expected for 2019 and onwards.

BRANTFORD KIRKWALL/PARKWAY D PROJECT COSTS
UNION RATE ZONES

1. In its Brantford-Kirkwall/Parkway D (EB-2013-0074) Decision, the OEB approved the establishment of the Brantford-Kirkwall/Parkway D Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Brantford-Kirkwall/Parkway D Project and the revenue requirement included in rates.

2. The balance in this deferral account is a credit to Union rate zone ratepayers of \$0.045 million plus interest of \$0.003 million for a total credit balance of \$0.045 million. The balance of \$0.045 million represents the difference between the revenue requirement of \$15.329 million included in 2021 rates (EB-2020-0095) and the calculation of the actual revenue requirement for 2021 of \$15.284 million as shown in Table 1. The small decline in the actual revenue requirement results from minor underages in the capital cost and municipal taxes of the project.

TABLE 1
2021 BRANTFORD-KIRKWALL PIPELINE/PARKWAY D PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2021 Board-approved (a)	Col. 2 2021 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	-	-
2.	Cumulative Capital Expenditures	197,404	197,378	(26)
3.	Average Investment	167,709	167,680	(29)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	-	-	-
5.	Depreciation Expense (1)	4,995	4,995	-
6.	Property Taxes	995	952	(43)
7.	Total Operating Expenses	5,990	5,947	(43)
8.	Required Return (2)	9,492	9,490	(2)
9.	Total Operating Expense and Return	15,482	15,437	(45)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	1,944	1,944	-
11.	Income Taxes - Utility Timing Differences (4)	(2,097)	(2,097)	-
12.	Total Income Taxes	(153)	(153)	-
13.	Total Revenue Requirement	15,329	15,284	(45)

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.82% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
$167.680 million * 64% * 3.82% = $4.099 million plus
$167.680 million * 36% * 8.93% = $5.39 million for a total of $9.490 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

UNACCOUNTED FOR GAS VOLUME DEFERRAL ACCOUNT
UNION RATE ZONES

1. The purpose of the Unaccounted for Gas (UFG) Volume Deferral Account is to capture the difference between the unit cost of UFG recovered in the rates approved by the OEB and actual UFG costs incurred. The amount of the UFG volume deferral account to be cleared to customers is subject to a symmetrical dead-band of $5.0 million, with amounts within such dead-band being to Enbridge Gas's account.

2. Union rate zones' 2021 Board Approved rates included $10.1 million in UFG costs. Based on 2021 actual volumes, Enbridge Gas recovered $10.4 million in UFG costs for 2021. In comparison, Enbridge Gas's actual 2021 UFG costs were $35.9 million. The difference of $25.5 million is above the $5.0 million threshold established by the OEB for the UFG Volume Variance Account. As a result, there is a debit balance of $20.5 million in the UFG Volume Deferral Account, plus interest of $0.2 million for a total debit balance of $20.7 million. See Table 1 below.

Table 1
2021 UTILITY UFG VARIANCES FROM BOARD-APPROVED

Line No.	Particulars	Variance ($Millions)
1	UFG Cost Included in Rates	$ 10.1
2	Net Recovery Variance	$ 0.3
3	Total UFG Collected in 2021 Rates (line 1 + line 2)	$ 10.4
4	Total Utility UFG Actual Cost	$ 35.9
5	Total Utility UFG Variance (line 3 - line 4)	-$ 25.5
6	$5M UFG Symmetrical Dead-band	$ 5.0
7	UFG Volume Deferral (receivable)	-$ 20.5

(1) Board Approved throughput w as 32,010 10^6m^3 versus actual throughput of 37,612 10^6m^3

(2) Board Approved UFG % is 0.219% versus actual UFG % of 0.672% for 2021.

3. The methodology for determining the actual UFG expense of $35.9 million in 2021 is consistent with the methodology historically used to calculate actual UFG for the audited Financial Statements, utility rate setting and earnings calculation.

4. Table 2 and Table 3 provide historical UFG volumes and percentage of throughput for the Union rate zone from 2001 to 2021.

Table 2: Historical UFG Percentage of Throughput for the Union Rate Zone

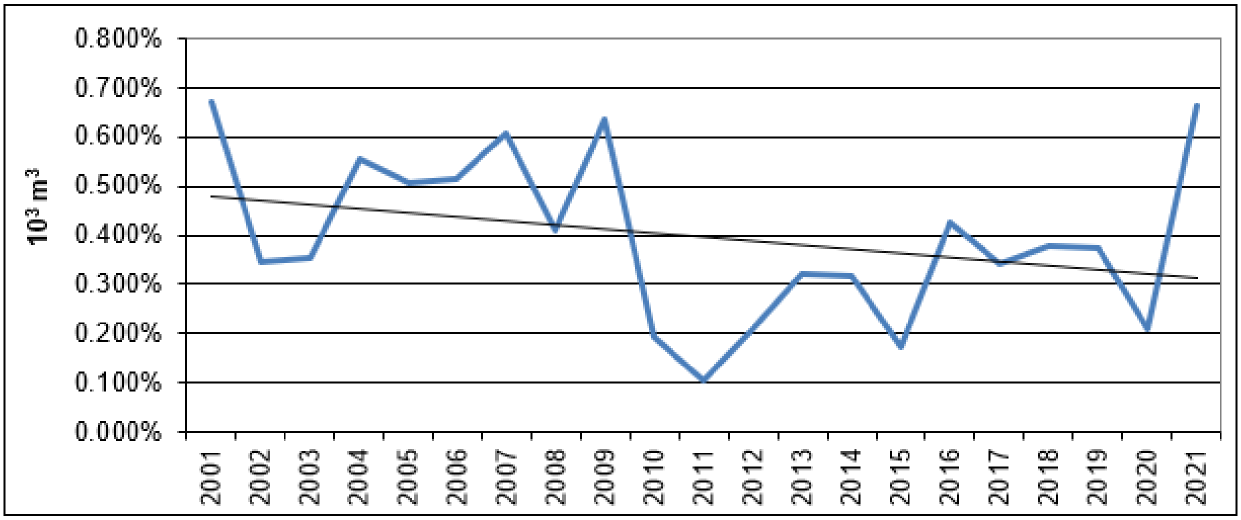

Table 3

Col.1	*Col.2*	*Col.3*
Calendar Year	**UFG Volumes (10^3 m^3)**	**UFG %**
2001	184,102	0.673%
2002	109,542	0.344%
2003	108,819	0.356%
2004	176,650	0.554%
2005	169,540	0.507%
2006	154,015	0.516%
2007	203,713	0.609%
2008	143,880	0.411%
2009	201,845	0.637%
2010	67,283	0.192%
2011	35,668	0.105%
2012	68,690	0.210%
2013	113,997	0.320%
2014	97,109	0.318%
2015	54,408	0.174%
2016	131,588	0.427%
2017	108,901	0.342%
2018	136,447	0.379%
2019	137,652	0.376%
2020	74,120	0.208%
2021	252,582	0.672%

5. The 0.219% UFG percentage used in approved rates was determined in EB-2011-0210 using the weighted average of the previous three years actual UFG. At the time 2013 rates were set, the most recent three years actual UFG available was 2009 to 2011. The Board approved methodology uses a 3:2:1 weighting with the most recent year weighted most heavily. The result was a ratio for UFG in rates influenced heavily by 2011’s favourable ratio. Concern over the ability to manage UFG relative to the new ratio was a factor in the establishment of a deferral account to capture variances, as was approved in EB-2013-0202.

6. Since the 2013 Board Approved percentage was determined, the average UFG percentage has been 0.356%, for the years of 2013 through 2021. Within that period of 2013 through 2021, the UFG % in 2015 was notably lower than the average, with a corresponding increase in 2016. Similarly, the UFG % in 2020 was lower than the average, with an increase in the UFG % observed in 2021.

7. As was noted in EB-2017-0091 Exhibit B.Staff.9, the increase in UFG volumes experienced in 2016 was primarily driven by a decrease in delivery volumes recorded in January 2016 relating to true-up of estimated consumption recorded in December 2015.

8. A similar decrease and offsetting increase in UFG volumes has been observed between the 2020 and 2021 calendar years. The average UFG % for 2020 and 2021 is 0.440%, which is approximately 163.5 10^3m^3/year average for the two years. The Company has identified that the true-up of estimated consumption based on the calendarization of UFG volumes has contributed to volatility between 2020 and 2021, but has not resulted in a material increase to the historical average of UFG over the course of two years. Typical estimation true-ups are outlined below.

9. At the end of each reporting period, Enbridge Gas records an estimate of gas delivered but not yet billed. The true-up between the December 2020 estimate and the actual billed volumes resulted in a decrease to the delivery volumes recorded in January 2021. This true-up reflects that, when billings related to December 2020 were completed over the following month, it was determined there was an over-estimate of gas deliveries for December 2020.

10. A second common estimation true-up is known as a prior period adjustment (PPA). PPAs are processed when there is a variance between a billed estimate and actual volumes. The inclusion of PPAs within the annual reported consumption volumes is

consistent with the methodology historically used to calculate actual UFG for the audited Financial Statements, utility rate setting and earnings sharing calculation.

11. The UFG volumes in 2020 were abnormally low compared to the historical average. The estimation true-up recorded in 2021 caused UFG volumes in 2021 to be elevated. As mentioned, the average of 2020 and 2021 is in line with the historical average of UFG volumes from 2013 to 2021.

12. Enbridge evaluated other factors that could have impacted UFG including, investigating meter reads between custody and check meters for inconsistencies, reviewing accounting processes associated with recording company use and line-pack changes, assessing impacts arising from the transition of Union rate zone customers to the SAP customer information system, and reviewing storage inventory adjustments. These items were deemed to have minimal impact on the elevated level of UFG in 2021. Enbridge is continuing to monitor and address potential contributors to UFG.

13. Volatility in UFG is not uncommon and is experienced across the gas utility industry. The 2019 UFG report prepared by ScottMadden filed in the 2020 Rates Application (EB-2019-0194) noted that:

> "….legacy Union and legacy EGD have year-to-year fluctuations in UFG levels that are generally consistent with those of other gas utilities. The fluctuations are a result of many factors, including weather, estimation variation, measurement variation, and billing and accounting adjustments. ……….all gas distribution pipeline systems have UFG as an element of operating a natural gas distribution system and that because of the numerous factors that impact UFG, the UFG percentage will fluctuate over time.[1]"

[1] EB-2019-0194, UFG Progress Report, page 4.

14. Enbridge Gas filed the 2019 UFG Study as part of the 2020 rate application (EB-2019-0194). The report found that the primary sources of UFG include physical losses (eg. leaks, third-party damage and venting), metering variations, non-registering meters, theft, line pack and billing and accounting adjustments (such as the estimate of gas delivered but not yet billed required at the end of each reporting period to report results). Although the root causes of UFG are generally known as described above, it continues to be difficult to quantify the individual factors due to their nature. Certain sources of UFG, such as leaks and emissions, contribute to baseline UFG while other sources such as billing, and accounting adjustments contribute to UFG volatility.

15. As committed by the Company in 2020 Rates application (EB 2019-0194), Enbridge Gas will file an update in the 2024 rebasing application about the implementation of the UFG report recommendations and other activities to address UFG, and the impacts of such activities.

UNACCOUNTED FOR GAS (UFG) PRICE VARIANCE ACCOUNT
UNION RATE ZONES

1. The UFG Price Variance Account captures the variance between the average monthly price of the Company's purchases for the Union rate zones and the applicable OEB-approved reference price, applied to the Company's actual UFG volumes for the Union rate zones. During 2021, the Company purchased 63,961 10^3m^3 of gas supply in Union rate zones related to actual UFG volumes on behalf of ratepayers. The actual UFG purchases exclude the actual UFG collected from ratepayers who provide UFG in kind as part of customer supplied fuel (CSF).

2. The average actual cost of the UFG purchases in 2021 is $52.52/$10^3m^3$ higher than the OEB-approved reference prices included in rates based on the Union South rate zone gas portfolio cost of $141.35/$10^3m^3$. The result is a $3.36 million balance to be collected from ratepayers, as shown in Table 1 below. Table 2 provides the detailed calculation supporting the price variance of $52.52/$10^3m^3$.

Table 1
Calculation of 2021 UFG Price Variance

Line No.		UFG Volumes (10^3m^3)
1	Experienced UFG [(1)]	270,030
2	UFG Collected through CSF	206,069
3	UFG Volumes – Company Supplied [(2)]	63,961
		Deferral Calculation
4	UFG Volumes (10^3m^3) – Company Supplied [(2)]	63,961
5	Price Variance ($\$/10^3m^3$) [(3)]	$52.52
6	Variance Account Balance ($ millions)	$3.36

(1) Converted using the follow ing heat values (39.28 Jan-Mar) (39.32 Apr – Dec).

(2) UFG Volumes represent gas supply related to actual UFG volumes on behalf of ratepayers w ho do not provide UFG in kind as part of CSF.

(3) See Table 2 for the price variance calculation. This represents w eighted average actul cost relative to OEB-approved reference prices.

Table 2
Calculation of 2021 Union South Price Varaince

Line No.	Union South Rate Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average Price
1.0	Board Approved Reference Price ($ / 10^3m^3)	$ 131.43	$ 131.43	$ 131.43	$ 135.62	$ 135.62	$ 135.62	$ 129.13	$ 129.13	$ 129.13	$ 169.23	$ 169.23	$ 169.23	$ 141.35
2.0	Actual Purchase ($)	$42,507,900	$45,125,048	$43,018,711	$32,580,518	$38,260,250	$36,250,196	$51,360,970	$55,362,122	$58,149,557	$60,445,476	$92,591,845	$92,645,865	
3.0	Purchase Volumes (10^3m^3)	325,958	294,013	281,053	249,025	268,780	268,626	286,082	274,130	267,494	208,408	307,429	318,118	
4.0	Average Purchase Cost (Union South) ($ / 10^3m^3)	$ 130.41	$ 153.48	$ 153.06	$ 130.83	$ 142.35	$ 134.95	$ 179.53	$ 201.96	$ 217.39	$ 290.03	$ 301.18	$ 291.23	$ 193.87
5.0	Union South Price Variance ($ / 10^3m^3) (1)	$ 1.02	$ (22.05)	$ (21.63)	$ 4.78	$ (6.73)	$ 0.67	$ (50.41)	$ (72.83)	$ (88.26)	$ (120.80)	$ (131.95)	$ (122.00)	$ (52.52)

Notes
(1) Line 1 - Line 4

LOBO C COMPRESSOR/HAMILTON MILTON PIPELINE PROJECT COSTS DEFERRAL ACCOUNT – UNION RATE ZONES

1. In its Dawn Parkway 2016 Expansion (EB-2014-0261) Decision, the OEB approved the establishment of the Lobo C Compressor/Hamilton-Milton Pipeline Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Project and the revenue requirement included in rates.

2. The balance in this deferral account is a debit from Union Rate Zone ratepayers of $0.024 million plus interest of $0.0003 million for a total debit balance of $0.024 million. The balance of $0.024 million represents the difference between the revenue requirement of $26.025 million included in 2021 rates (EB-2020-0095) and the calculation of the actual revenue requirement for 2021 of $26.049 million as shown in Table 1.

TABLE 1
2021 LOBO C COMPRESSOR/HAMILTON-MILTON PIPELINE PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2021 Board-approved (a)	Col. 2 2021 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	-	-
2.	Cumulative Capital Expenditures	347,980	347,062	(918)
3.	Average Investment	306,868	306,005	(863)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	863	1,104	241
5.	Depreciation Expense (1)	8,261	8,214	(47)
6.	Property Taxes	1,210	1,056	(154)
7.	Total Operating Expenses	10,334	10,374	40
8.	Required Return (2)	16,464	16,417	(47)
9.	Total Operating Expense and Return	26,798	26,791	(7)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	3,562	3,547	(15)
11.	Income Taxes - Utility Timing Differences (4)	(4,335)	(4,289)	46
12.	Total Income Taxes	(773)	(742)	31
13.	Total Revenue Requirement	26,025	26,049	24

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.36% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
$306.868 million * 64% * 3.36% = $6.599 million plus
$306.868 million * 36% * 8.93% = $9.865 million for a total of $16,464 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Average Investment

3. The average investment decrease of $0.863 million from OEB-approved is due to the cumulative capital expenditures being $0.918 million lower than OEB-approved capital expenditures.

2. Operating Expenses

4. Operating and maintenance expenses were $0.241 million higher than the costs included in 2021 OEB-approved rates. The increase is a result of higher salaries/wages related to overtime costs not included in the original budget and pertain to the annual operations and general maintenance of the equipment and assets.

3. Property Tax

5. Property taxes were $0.154 million lower than costs included in 2021 OEB-approved rates. The decrease is a result of Provincial tax reductions for business education tax rates on commercial, industrial, and pipeline tax in 2021.

LOBO D/BRIGHT C/DAWN H COMPRESSOR PROJECT COSTS
UNION RATE ZONES

1. In its EB-2015-0116 Decision, the OEB approved the establishment of the Lobo D/Bright C/Dawn H Compressor Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Lobo D/Bright C/Dawn H Compressor Project and the revenue requirement included in rates.

2. The balance in this deferral account is a credit to Union Rate Zone ratepayers of \$0.112 million plus interest of \$0.004 million, for a total credit balance of \$0.116 million. The balance of \$0.116 million includes a debit of \$1.225 million which represents the difference between the revenue requirement of \$45.154 million included in 2021 rates (EB-2020-0095) and the calculation of the actual revenue requirement for 2021 of \$46.379 million as shown in Table 1.

3. A \$1.337 million credit relates to the 2021 revenue generated from the sale of surplus Dawn Parkway system capacity of 30,393 GJ/day associated with the Lobo D/Bright C/Dawn H Compressor Project. In accordance with the 2018 Disposition of Deferral and Variance Account Balances and Utility Earnings proceeding (EB-2019-0105) approved Settlement Proposal, the surplus capacity is deemed to be sold long-term and the revenue credit for the 2021 year is calculated based on the M12 Dawn-Parkway rate of \$3.665/GJ approved in the EB-2020-0181 Rate Order, dated May 18, 2021. A schedule supporting the 2021 revenue calculation is provided at Exhibit E, Tab 1, Schedule 7.

TABLE 1

2021 DAWN H/LOBO D/BRIGHT C COMPRESSOR PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2021 Board-approved (a)	Col. 2 2021 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	-	-
2.	Cumulative Capital Expenditures	622,500	620,050	(2,450)
3.	Average Investment	552,367	551,923	(444)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	1,761	2,675	914
5.	Depreciation Expense (1)	17,418	17,437	19
6.	Property Taxes	1,089	1,031	(58)
7.	Total Operating Expenses	20,268	21,143	875
8.	Required Return (2)	29,388	29,364	(24)
9.	Total Operating Expense and Return	49,656	50,507	851
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	6,402	6,397	(5)
11.	Income Taxes - Utility Timing Differences (4)	(10,905)	(10,526)	379
12.	Total Income Taxes	(4,503)	(4,129)	374
13.	Total Revenue Requirement	45,154	46,379	1,225

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.29% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
$552.367 million * 64% * 3.29% = $11.631 million plus
$552.367 million * 36% * 8.93% = $17.757 million for a total of $29.388 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Average Investment

4. The average investment decrease of $0.444 million from OEB-approved is due to the cumulative capital expenditures being $2.450 million lower than OEB-approved.

2. Operating Expenses

5. Operating and maintenance expenses were $0.914 million higher than the costs included in 2021 OEB-approved rates. The increase is a result of higher salaries/wages as the budget did not account for overtime costs, higher general maintenance costs than budgeted, and higher utility costs than budgeted. Salary/wages costs were not capitalized or captured in contingency costs as they were incurred for the annual operations and general maintenance of the equipment and assets. Table 2 shows the breakdown and comparison of actual 2021 operating and maintenance costs versus OEB-approved.

TABLE 2
2021 DAWN H/LOBO D/BRIGHT C COMPRESSOR OPERATING AND MAINTENANCE EXPENSES

Line No.	Particulars ($Millions)	Col. 1 2021 Board-approved (a)	Col. 2 2021 Actuals (b)	Col. 3 Difference (c) = (b - a)
1.	Salaries & Wages	870	1,285	415
2.	HR Costs	392	576	184
3.	Fleet Costs	131	193	62
4.	Training, Travel and PE	67	12	(55)
5.	Other O&M (Contract Services)	165	307	142
6.	Company Used Fuel	73	-	(73)
7.	Utility Costs	63	302	239
8.	Total Capital Expenditures	1,761	2,675	914

3. Income Taxes

6. The $0.379 million decrease in “Income Taxes – Utility Timing Difference” credit relates to a lower Capital Cost Allowance (CCA) deduction due to the lower average investment in 2021, versus OEB-approved, as well as lower CCA available on additions that were previously qualified for Bill C-97 accelerated CCA.

BURLINGTON OAKVILLE PROJECT COSTS DEFERRAL ACCOUNT
UNION RATE ZONES

1. In its EB-2015-0116 Decision, the OEB approved the establishment of the Burlington Oakville Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Project and the revenue requirement included in rates.

2. The balance in this deferral account is a credit to Union rate zone ratepayers of $0.051 million plus interest of $0.0004 million for a total credit balance of $0.051 million. The balance of $0.051 million represents the difference between the revenue requirement of $5.707 million included in 2021 rates (EB-2020-0095) and the calculation of the actual revenue requirement for 2021 of $5.656 million as shown in Table 1. The small decline in the actual revenue requirement results from minor underages in the capital cost and operating costs of the project.

TABLE 1
2021 BURLINGTON OAKVILLE PIPELINE PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2021 Board-approved (a)	Col. 2 2021 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	-	-
2.	Cumulative Capital Expenditures	83,349	83,262	(87)
3.	Average Investment	74,814	74,725	(89)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	17	-	(17)
5.	Depreciation Expense (1)	1,732	1,737	5
6.	Property Taxes	134	116	(18)
7.	Total Operating Expenses	1,883	1,853	(30)
8.	Required Return (2)	4,014	4,009	(5)
9.	Total Operating Expense and Return	5,897	5,862	(35)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	868	866	(2)
11.	Income Taxes - Utility Timing Differences (4)	(1,058)	(1,072)	(14)
12.	Total Income Taxes	(190)	(206)	(16)
13.	Total Revenue Requirement	5,707	5,656	(51)

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.36% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
$74.814 million * 64% * 3.36% = $1.609 million plus
$74.814 million * 36% * 8.93% = $2.405 million for a total of $4.014 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

2021 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT
UNION RATE ZONES

1. The purpose of the 2021 Ontario Energy Board Cost Assessment Variance Account (OEBCAVA) was to record any variances between the OEB costs assessed to Enbridge Gas (relevant to the Union rate zones) through application of the revised Cost Assessment Model (CAM), which became effective April 1, 2016, and the OEB costs which were included in Union rate zones rates, which were determined through application of the prior CAM. The scope of the account is consistent with prior OEBCAVAs. However, in accordance with the EB-2020-0134 OEB-approved Settlement Proposal, in Enbridge Gas's 2019 Earnings Sharing and Deferral Disposition proceeding, the base OEB costs assumed to be included in rates have been escalated to the reflect the growth in the amount recovered through rates, which results from annual price cap adjustments and customer growth. The OEBCAVA was originally approved for establishment by OEB letter dated February 9, 2016, entitled: *Revisions to the Ontario Energy Board Cost Assessment Model.*

2. The amount recorded within the 2021 OEBCAVA is a $0.907 million debit plus interest of $0.011 million for a total debit balance of $0.919 million. This amount reflects the variance between OEB costs assessed to Enbridge Gas (relevant to Union rate zones) in each quarter of fiscal 2021, utilizing the revised CAM, and Union's average quarterly OEB cost assessment under the prior CAM, escalated in accordance with the EB-2020-0134 OEB-approved Settlement Proposal.

3. In order to calculate the amount to be recovered through the 2021 Union rate zones OEBCAVA, the Company first needed to apportion the actual 2021 OEB assessed costs between the legacy rate zones. Commencing with the OEB's 2019/2020 fiscal

first quarter assessment (for the period April 1, 2019 through June 30, 2019), and continuing since, EGI has been receiving one consolidated quarterly bill for the amalgamated utility. To apportion the quarterly assessments received in 2021 between rate zones, the assessments were prorated based on the total invoices received by each legacy utility for the OEB's 2018/2019 fiscal year (for the period April 1, 2018 through March 31, 2019), the final year for which the OEB issued invoices to each legacy utility. Table 1 below shows the proration of the OEB's 2018/2019 fiscal year assessments between each legacy utility/rate zone (59.76% EGD rate zone, 40.24% Union rate zones). Table 2 shows the apportionment of EGI's 2021 assessed costs to the Union rate zones, and the calculation of the amount recorded in the 2021 Union rate zones OEBCAVA.

4. To calculate the amount for recovery through the 2021 Union rate zones OEBCAVA, the Company also needed to establish the base comparator, reflecting the OEB costs included in Union rate zones rates, determined through application of the prior Cost Assessment Model. In accordance with the EB-2020-0134 OEB approved Settlement Proposal, the amount reflected in rates is also to be increased, or escalated, to reflect the growth in the amount recovered as a result of annual price cap adjustments and customer growth. To establish the 2021 base comparator, the Company escalated the 2020 quarterly comparator of $0.718 million by the sum of the 2021 Price Cap Index (PCI) of 1.70%, and the Union rate zones ICM threshold calculation Growth Factor (g) of 1.46%, which were approved as part of EGI's 2021 Rate Application, EB-2020-0181. The escalation resulted in a 2021 quarterly comparator of $0.741 million ($0.718 million * (1 + (1.70% + 1.46%))). As noted above, Table 2 below shows the apportionment of EGI's actual 2021 assessed costs to the Union rate zones, and the calculation of the amount recorded in the 2021 Union rate zones OEBCAVA utilizing a base comparator of $0.741 million.

5. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2021 OEBCAVA, in the amount of $0.907 million and $0.011 million respectively, as shown in Exhibit C, Tab 1, Schedule 1.

Table 1

OEB 2018/2019 Cost Assessments

	EGD	UGL	Total
Apr. 1 to Jun. 30, 2018	1,467,963.00	988,479.00	2,456,442.00
Jul. 1 to Sep. 30, 2018	1,356,860.00	913,873.00	2,270,733.00
Oct. 1 to Dec. 31, 2018	1,356,860.00	913,873.00	2,270,733.00
Jan. 1 to Mar. 31, 2019	1,356,860.00	913,873.00	2,270,733.00
	5,538,543.00	3,730,098.00	9,268,641.00
Percentage of Total	59.76%	40.24%	100.00%

Table 2

Calculation of 2021 UGL RZ OEBCAVA

Period	EGI Assessment	UGL Rate Zones Share (40.24%)	Average cost assessment Comparator	Variance to UGL Rate Zone OEBCAVA
Jan. 1 to Mar. 31, 2021	2,497,219.00	1,004,987.85	741,052.94	263,934.91
Apr. 1 to Jun. 30, 2021	2,364,191.00	951,451.69	741,052.94	210,398.75
Jul. 1 to Sep. 30, 2021	2,379,076.00	957,442.05	741,052.94	216,389.11
Oct. 1 to Dec. 31, 2021	2,379,076.00	957,442.05	741,052.94	216,389.11
				907,111.89

2021 BASE SERVICE NORTH T-SERVICE TRANSCANADA CAPACITY DEFERRAL ACCOUNT – UNION RATE ZONE

1. In the EB-2015-0181 decision, the OEB approved a new optional Union North T-service Transportation from Dawn to allow T-service customers in the Union North East Zone with access to Dawn-based supply. To facilitate this service, Enbridge Gas was required to contract for 15-year transportation capacity with TransCanada from Parkway to the Union CDA, Union NCDA and Union EDA. The approved rates for the service are equal to the EGI C1 rate from Dawn to Parkway and the TransCanada Firm Transportation (FT) toll to Delivery Area.

2. The purpose of the North T-service TransCanada Capacity Deferral Account is to record the difference between the costs for the capacity from Parkway to the northern Delivery Area as part of the Base Service offering of the North T-Service Transportation from Dawn and the demand revenues collected from the North T-Service customers.

3. The total cost Enbridge Gas paid for the contracted TransCanada capacity in 2021 was $2.172 million or $180,961.81 per month. On an actual basis, the Company collected $2.088 million demand revenues from the North T-service customers. As a result, the balance of the 2021 North T-service TransCanada Capacity Deferral Account is a collection from ratepayers of $0.084 million plus interest of $0.0001 million and the balance will be cleared amongst all North T-service from Dawn customers. The variance is driven by a net reduction of 313 GJ/day of contracted capacity by North T-service customers.

PANHANDLE REINFORCEMENT PROJECT COSTS DEFERRAL ACCOUNT
UNION RATE ZONES

1. In its Panhandle Reinforcement Project (EB-2016-0186) Decision, the OEB approved the establishment of the Panhandle Reinforcement Project Costs Deferral Account to track the differences between the actual net revenue requirement related to costs for the Project and the net revenue requirement included in rates.

2. The balance in this deferral account is a credit to Union rate zone ratepayers of $3.162 million plus interest of $0.021 million for a total credit balance of $3.183 million. The balance of $3.162 million represents the difference between the net revenue requirement of $10.701 million included in 2021 rates (EB-2020-0095) and the calculation of the actual net revenue requirement for 2021 of $7.539 million as shown in Table 1.

TABLE 1
2021 PANHANDLE REINFORCEMENT PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2021 Board-approved (a)	Col. 2 2021 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	-	-
2.	Cumulative Capital Expenditures	232,844	228,574	(4,270)
3.	Average Investment	213,957	209,844	(4,113)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	16	-	(16)
5.	Depreciation Expense (1)	4,944	4,921	(23)
6.	Property Taxes	1,812	1,590	(222)
7.	Total Operating Expenses	6,773	6,511	(262)
8.	Required Return (2)	11,383	11,165	(218)
9.	Total Operating Expense and Return	18,156	17,676	(480)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	2,480	2,432	(48)
11.	Income Taxes - Utility Timing Differences (4)	(3,691)	(3,693)	(2)
12.	Total Income Taxes	(1,211)	(1,261)	(50)
13.	Total Revenue Requirement	16,945	16,415	(530)
14.	Incremental Project Revenue	6,243	8,876	2,633
15.	Net Revenue Requirement	10,701	7,539	(3,162)

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
$213.957 million * 64% * 3.29% = $4.505 million plus
$213.957 million * 36% * 8.93% = $6.878 million for a total of $11.383 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Average Investment

3. The average investment decrease of $4.113 million from OEB-approved is due to the cumulative capital expenditures being $4.270 million lower than OEB-approved.

2. Property Tax

4. Property taxes were $0.222 million lower than costs included in 2021 OEB-approved rates. The decrease is a result of Provincial tax reductions for business education tax rates on commercial, industrial, and pipeline tax in 2021.

3. Required Return

5. The decrease in the required return of $0.218 million is the result of a decrease in the average rate base.

4. Incremental Project Revenue

6. The actual incremental revenue of $8.876 million reflects the continued addition of new customers and expansion by existing customers in the Panhandle market, primarily in the greenhouse sector and is $2.633 million higher than the forecast incremental revenue included in 2021 Rates.

2021 PENSION AND OPEB FORECAST ACCRUAL VS ACTUAL CASH PAYMENT DIFFERENTIAL VARIANCE ACCOUNT – UNION RATE ZONES

1. In its EB-2015-0040 report to all regulated entities, dated September 14, 2017, titled *"Regulatory Treatment of Pension and Other Post-employment Benefits (OPEB) Costs",* the OEB ordered the establishment of the deferral account, effective January 1, 2018, to be used by utilities that are approved to recover their pension and OPEB costs on an accrual basis[1]. The Company recovers its pension and OPEB costs on an accrual basis.

2. The purpose of the Pension and OPEB Forecast Accrual vs Actual Cash Payment Differential Variance Account is to track the differences between forecast accrual pension and OPEB amounts recovered in rates, and the actual cash payments made for both pension and OPEB, on a go-forward basis from the date the account was established.

3. In 2021, the accrual pension and OPEB amount recovered in rates for the Union rate zones was $47.4 million and the actual cash payments made for both pension and OPEB were $22.6 million, resulting in an annual $24.8 million credit variance. The variance carried forward from 2020 is a $50.4 million credit variance, resulting in a cumulative $75.2 million credit variance through 2021.

4. In accordance with the OEB's Report (EB-2015-0040), when the cumulative forecasted accrual amount recovered in rates exceeds the cumulative actual cash payments, an asymmetrical carrying charge, to be returned to ratepayers, should be accrued based on the opening monthly difference between amount recovered in

[1] EB-2015-0040, *Regulatory Treatment of Pension and Other Post-employment Benefits ("OPEB") Costs*, September 14, 2017, page 2.

rates and actual cash payments. The balance in the account for 2021 is an interest credit to ratepayers of $1.346 million to December 31, 2021[2]. Table 1 sets out the detailed calculation of the forecast accrual versus actual cash payments, and associated interest.

TABLE 1

DETAILS OF 2021 INTEREST CALCULATED ON FORECAST ACCRUALS VS ACTUAL CASH PAYMENTS
IN PENSION AND OPEB VARIANCE ACCOUNT (NO. 179-157)

Particulars ($000's)	20-Dec	21-Jan	21-Feb	21-Mar	21-Apr	21-May	21-Jun	21-Jul	21-Aug	21-Sep	21-Oct	21-Nov	21-Dec	Total
Forecast accrual amounts		3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	47,416
Actual cash payments		4,351	506	982	5,796	181	937	3,133	155	997	4,138	43	1,394	22,614
Monthly variance		400	-3,445	-2,970	1,845	-3,770	-3,015	-818	-3,797	-2,954	187	-3,908	-2,557	-24,803
Cumulative variance	-50,367	-49,967	-53,412	-56,382	-54,537	-58,307	-61,322	-62,140	-65,936	-68,891	-68,704	-72,612	-75,169	
OEB prescribed CWIP rate		2.03	2.03	2.03	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	
Asymmetrical interest		-87	-78	-92	-106	-109	-111	-117	-119	-126	-131	-131	-139	-1,346

[2] Interest is as of December 31, 2021, as interest on this account is calculated on a cumulative account balance basis.

ACCOUNTS WITH A ZERO BALANCE
UNION RATE ZONES

1. The following 2021 accounts for the Union rate zones have no balance, and are therefore not requested for clearance to customers:
    - Spot Gas Variance Account
    - Unbundled Services Unauthorized Storage Overrun Deferral Account
    - Gas Distribution Access Rule (GDAR) Costs Deferral Account
    - Conservation Demand Management Deferral Account
    - Sudbury Replacement Project Costs Deferral Account
    - Parkway Obligation Rate Variance Deferral Account
    - Unauthorized Overrun Non-Compliance Account

TRANSPORTATION OPTIMIZATION DEFERRAL ACCOUNT - UNION RATE ZONES

Line No.	Particulars	Col. 1 2013 Board Approved	Col. 2 2020 Actual Total	Col. 3 2021 Actual Total
		($000's)	($000's)	($000's)
1.	Base Exchange Revenue	(9,118.00)	(4,243.99)	(7,528.52)
2.	FT RAM Exchange Revenue	(5,800.00)		
3.	Total Exchange Revenue	(14,918.00)	(4,243.99)	(7,528.52)
4.	Exchange Revenue Subject to Deferral		(4,243.99)	(7,528.52)
5.	Ratepayer portion - 90%	(13,426.20)	(3,819.59)	(6,775.67)
6.	10% Union Incentive Payment		(424.40)	(752.85)
7.	Less: Gas Supply Optimization Margin in Rates	13,426.00	15,943.18	15,391.98
8.	2021 Deferral Account Balance receivable from Ratepayers		12,123.59	8,616.31

BREAKDOWN OF SHORT TERM STORAGE DEFERRAL ACCOUNT (STSDA) - UNION RATE ZONES

Line No.	Particulars ($000's)	Col .1 Board-Approved 2013	Col. 2 Actual 2020	Col. 3 Actual 2021
	Revenue			
1.	C1 Off-Peak Storage	500	1,002	433
2.	Supplemental Balancing Services	2,000	1,016	640
3.	Gas Loans		1	1
4.	LBA		0	0
5.		2,500	2,019	1,075
6.	C1 ST Firm Peak Storage	7,883	2,715	1,536
7.	Total Revenue (1)	10,383	4,735	2,610
	Costs			
8.	O&M (2)	3,810	782	1,004
9.	UFG (3)	316	114	266
10.	Compressor Fuel (4)	1,201	196	257
11.	Total Costs	5,327	1,091	1,528
12.	Net Revenue (line 7 - 11)	5,056	3,644	1,082
13.	Less Shareholder Portion (10%)	505	364	108
14.	Ratepayer Portion	4,551	3,279	974
15.	Approved in Rates	4,551	4,551	4,551
16.	Deferral balance payable to / (collectable from) ratepayers	(0)	(1,272)	(3,577)

Notes:
(1) Based on short-term storage services provided
(2) Revenue Requirement on 11.3 PJ's of board approved excess in-franchise storage capacity
(3) Based on short-term storage volumes in proportion to total volumes
(4) Based on short-term storage activity in proportion to total actual storage activity

ENBRIDGE GAS INC.
2021 Storage Space & Deliverability

Line No.	Particulars	2021 (1) Storage Space (2) (PJ)		2021 (1) Storage Deliverability (2) (GJ/d)
		(a)		(b)
	Union North Rate Zone			
1	Rate 01	12.2		212,035
2	Rate 10	2.9		60,957
3	Rate 20	2.4		35,273
4	Rate 25	-		-
5	Rate 100	0.1		1,139
6	Total Union North Rate Zone	17.5		309,405
	Union South Rate Zone			
7	Rate M1	40.0		990,924
8	Rate M2	10.6		318,002
9	Rate M4	2.9		174,198
10	Rate M5	0.0		291
11	Rate M7	2.1		67,205
12	Rate M9	0.3		9,448
13	Rate M10	0.0		145
14	Rate T1	1.5		40,947
15	Rate T2	9.3		200,945
16	Rate T3	3.2		70,931
17	Total Union South Rate Zone	70.0		1,873,036
	Ex-Franchise			
18	Excess Utility Storage	3.0	(3)	35,816
19	Rate C1	-		-
20	Rate M12	-		-
21	Rate M13	-		-
22	Rate M16	-		-
23	Total Ex-Franchise	3.0		35,816
24	System Integrity Space	9.5		-
25	Total Union Rate Zone	100.0		2,218,257
	EGD Rate Zone			
26	Rate 1	61.2		1,208,141
27	Rate 6	58.7		962,711
28	Rate 9	-		-
29	Rate 100	-		-
30	Rate 110	2.2		5,076
31	Rate 115	0.5		2,013
32	Rate 125	-		-
33	Rate 135	-		-
34	Rate 145	0.3		-
35	Rate 170	0.8		-
36	Rate 200	2.0		20,355
37	Total EGD Rate Zone	125.8		2,198,296
38	Total Enbridge Gas (line 25 + line 37)	225.8		4,416,553

Notes:
(1) Allocation to rate classes using OEB-approved cost allocation methodologies.
(2) Union rate zone storage space based on actual W21/22 usage and storage deliverability based on forecast W21/22 requirements. EGD rate zone storage space and deliverability based on 2021 Gas Supply plan.
(3) EB-2022-0110, Exhibit E, Tab 1, page 6.

SUMMARY OF NON-UTILITY STORAGE BALANCES - UNION RATE ZONES

Date	Entitlement (PJ)	Balance (PJ)	% Full (%)	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
1-Oct-21	127.6	118.8	93.1%	1-Nov-21	127.6	121.4	95.1%
2-Oct-21	127.6	119.0	93.2%	2-Nov-21	127.6	121.4	95.2%
3-Oct-21	127.6	118.9	93.2%	3-Nov-21	127.6	121.2	95.0%
4-Oct-21	127.6	118.6	93.0%	4-Nov-21	127.6	121.2	95.0%
5-Oct-21	127.6	118.5	92.9%	5-Nov-21	127.6	121.4	95.2%
6-Oct-21	127.6	118.6	93.0%	6-Nov-21	127.6	121.6	95.3%
7-Oct-21	127.6	118.7	93.0%	7-Nov-21	127.6	121.8	95.4%
8-Oct-21	127.6	118.7	93.0%	8-Nov-21	127.6	121.7	95.4%
9-Oct-21	127.6	118.9	93.2%	9-Nov-21	127.6	122.2	95.8%
10-Oct-21	127.6	119.0	93.3%	10-Nov-21	127.6	122.9	96.3%
11-Oct-21	127.6	119.2	93.4%	11-Nov-21	127.6	123.8	97.0%
12-Oct-21	127.6	119.2	93.4%	12-Nov-21	127.6	124.5	97.6%
13-Oct-21	127.6	119.3	93.5%	13-Nov-21	127.6	125.1	98.1%
14-Oct-21	127.6	119.3	93.5%	14-Nov-21	127.6	125.2	98.1%
15-Oct-21	127.6	119.4	93.6%	15-Nov-21	127.6	125.2	98.1%
16-Oct-21	127.6	119.6	93.8%	16-Nov-21	127.6	125.4	98.3%
17-Oct-21	127.6	119.7	93.9%	17-Nov-21	127.6	125.9	98.7%
18-Oct-21	127.6	119.7	93.9%	18-Nov-21	127.6	126.1	98.9%
19-Oct-21	127.6	119.7	93.8%	19-Nov-21	127.6	125.9	98.7%
20-Oct-21	127.6	119.7	93.9%	20-Nov-21	127.6	125.9	98.7%
21-Oct-21	127.6	119.8	93.9%	21-Nov-21	127.6	125.9	98.7%
22-Oct-21	127.6	119.8	93.9%	22-Nov-21	127.6	125.1	98.1%
23-Oct-21	127.6	119.9	94.0%	23-Nov-21	127.6	124.3	97.4%
24-Oct-21	127.6	120.1	94.1%	24-Nov-21	127.6	124.1	97.3%
25-Oct-21	127.6	120.1	94.1%	25-Nov-21	127.6	124.0	97.2%
26-Oct-21	127.6	120.2	94.2%	26-Nov-21	127.6	123.9	97.1%
27-Oct-21	127.6	120.3	94.3%	27-Nov-21	127.6	123.5	96.8%
28-Oct-21	127.6	120.6	94.5%	28-Nov-21	127.6	122.9	96.3%
29-Oct-21	127.6	120.9	94.8%	29-Nov-21	127.6	122.2	95.8%
30-Oct-21	127.6	121.1	94.9%	30-Nov-21	127.6	121.7	95.4%
31-Oct-21	127.6	121.3	95.1%				

ALLOCATION OF SHORT TERM PEAK STORAGE REVENUES
BETWEEN UTILITY AND NON UTILITY - UNION RATE ZONES

Line No.	Particulars	Utility Storage Space (PJs)	Short Term Peak Storage Sold (PJs)	Revenue from Short Term Peak Storage ($ millions)
1	Net Revenues from Short Term Peak Storage			1.5
2	Total Short Term Peak Storage Sales		3.0	
3	Storage Space reserved for Utility	100.0		
4	Utility Space Requirement	97.0		
5	Excess Utility Storage Space (1)	3.0		
6	Total Utility Short Term Peak Storage Sales (2)		3.0	
7	Total Non Utility Short Term Peak Storage Sales		0.0	
8	Short Term Peak Storage Net Revenues - Utility (3)			1.5
9	Short Term Peak Storage Net Revenues - Non Utility (4)			-

Notes:
(1) line 3 - line 4
(2) line 2
(3) line 6 /line 2 *line
(4) line 7/ line 2* line 1

DEFERRAL VARIANCE CLEARING ACCOUNT - UNION RATE ZONES
2019 ESM (EB-2020-0134), 2017-2018 DSM (EB-2020-0067)
DISPOSITIONS DISPOSED OF DURING 2021

		2021			
Line No.	Particulars ($000)	2019 ESM Deferral EB-2020-0134	2017-18 DSM Deferral EB-2020-0067	Interest (1)	Total
		(a)	(b)	(c)	(d) = (a) + (b) + (c)
1.	Prospective Recovery/(Refund) - Delivery	(2,233)	(1,990)	(63)	(4,285)
2.	Prospective Recovery/(Refund) - Gas Supply Transportation	(1,447)		(21)	(1,469)
3.	Prospective Recovery/(Refund) - Gas Supply Commodity	1,698		25	1,723
4.	Sub-Total	(1,982)	(1,990)	(59)	(4,030)
5.	Manual Re-bills and other one-time billing adjustments				20
6.	Grand Total				(4,010)

(1) Interest forecasted to December 31, 2022.

DEFERRAL VARIANCE CLEARING ACCOUNT - UNION RATE ZONES
2017/2018 DSM DEFERRAL DISPOSITION (EB-2020-0067)
DISPOSITION PERIOD - APRIL1, 2021 TO SEPTEMBER 30, 2021

Line No.	Particulars	Rate Class	2021 Forecast Volume (10^3m^3) (1)	Actual Volume (10^3m^3)	Volume Variance (10^3m^3)	2017 DSM Unit Rate for Prospective Recovery/(Refund) (cents/m^3)	2018 DSM Unit Rate for Prospective Recovery/(Refund) (cents/m^3)	Forecast ($000)	Actual ($000)	Variance ($000)
			(a)	(b)	(c)	(d)	(e)	(f) = ((a) * (d)/100) + ((a) * (e)/100))	(g) = ((b) * (d)/100) + ((b) * (e)/100))	(h) = (f) - (g)
	General Service for Prospective Recovery(Refund) - Delivery									
1	Small Volume General Service	01	218,218	206,105	12,113	(0.9140)	(0.8186)	(3,781)	(3,571)	(210)
2	Large Volume General Service	10	97,893	82,334	15,559	(0.8698)	(1.3393)	(2,163)	(1,819)	(344)
3	Small Volume General Service	M1	708,032	724,452	(16,420)	2.3352	2.5733	34,754	35,560	(806)
4	Large Volume General Service	M2	373,184	322,222	50,962	(0.5157)	(0.7207)	(4,614)	(3,984)	(630)
5	Total General Service for Prospective Recovery (Refund) - Delivery		1,397,327	1,335,112	62,215			24,196	26,186	(1,990)
6	Total							24,196	26,186	(1,990)

Notes:
(1) Forecast volume for the period April 1, 2021 to September 30, 2021.

DEFERRAL VARIANCE CLEARING ACCOUNT - UNION RATE ZONES
2019 DEFERRAL DISPOSITION (EB-2020-0134)
DISPOSITION PERIOD - OCTOBER 1, 2021 TO DECEMBER 31, 2021

Line No.	Particulars	Rate Class	2021 Forecast Volume (10³m³) (1)	Actual Volume (10³m³)	Volume Variance (10³m³)	Unit Rate for Prospective Recovery/(Refund) (cents/m³) (2)	Forecast ($000)	Actual ($000)	Variance ($000)
			(a)	(b)	(c)	(d)	(e) = (a) * (d)/100	(f) = (b) * (d)/ 100	(g) = (c) - (f)
	General Service for Prospective Recovery(Refund) - Delivery								
1	Small Volume General Service	01	321,283	275,592	45,691	(1.0715)	(3,443)	(2,953)	(490)
2	Large Volume General Service	10	113,056	83,501	29,555	(1.1691)	(1,322)	(976)	(346)
3	Small Volume General Service	M1	951,810	822,199	129,611	(0.6869)	(6,538)	(5,648)	(890)
4	Large Volume General Service	M2	429,887	313,806	116,081	(0.4369)	(1,878)	(1,371)	(507)
5	Total General Service for Prospective Recovery (Refund) - Delivery		1,816,036	1,495,097	320,939		(13,180)	(10,948)	(2,233)
	General Service for Prospective Recovery(Refund) - Gas Supply Transportation								
6	Small Volume General Service-NW	01	90,838	80,740	10,098	(8.0456)	(7,308)	(6,496)	(812)
7	Small Volume General Service-NE	01	230,446	194,851	35,595	(0.4405)	(1,015)	(858)	(157)
8	Large Volume General Service-NW	10	27,145	19,561	7,584	(5.4548)	(1,481)	(1,067)	(414)
9	Large Volume General Service-NE	10	84,374	62,677	21,697	(0.2959)	(250)	(185)	(64)
10	Total General Service for Prospective Recovery (Refund) - Gas Supply Transportation		432,803	357,830	74,973		(10,054)	(8,607)	(1,447)
	Prospective Recovery/(Refund) - Gas Supply Commodity								
11	Small Volume General Service	M1	889,983	771,375	118,608	0.7902	7,033	6,095	937
12	Large Volume General Service	M2	224,466	139,468	84,998	0.7902	1,774	1,102	672
13	Firm Com/Ind Contract	M4	20,550	15,982	4,568	0.7902	162	126	36
14	Interruptible Com/Ind Contract	M5	2,744	625	2,119	0.7902	22	5	17
15	Special Large Volume Contract	M7	7,927	7,534	393	0.7902	63	60	3
16	Large Wholesale	M9	10,631	6,454	4,177	0.7902	84	51	33
17	Small Wholesale	M10	125	101	24	0.7902	1	1	0
18	Total Prospective Recovery (Refund) - Gas Supply Commodity		1,156,427	941,540	214,886		9,138	7,440	1,698
19	Total						(14,096)	(12,115)	(1,982)

Notes:
(1) Forecast volume for the period October 1, 2021 to December 31, 2021.
(2) Unit rate for prospective recovery/refund for each rate class equal to the gas supply commodity weighted-average unit rate.

UNION RATE ZONES
Calculation of Balances by Rate Class in the NAC Deferral Account (No. 179-133) - Base Rates and Y-Factor

Line No.	Particulars		Rate 01 (a)	Rate 10 (b)	Rate M1 (c)	Rate M2 (d)	Net Account Balance (e)
	Base Rates						
1	2021 Target NAC: m³		2,889.4	171,539.6	2,775.7	168,419.3	
2	2021 Actual NAC: m³		2,765.6	151,410.7	2,667.6	149,839.7	
3	Actual change in NAC: m³ (line 1 - 2)		123.7	20,128.9	108.1	18,579.6	
	Y Factor Rates						
4	2021 Target NAC: m³		2,829.8	166,842.2	2,691.8	169,476.8	
5	2021 Actual NAC: m³		2,765.6	151,410.7	2,667.6	149,839.7	
6	Actual change in NAC: m³ (line 4 - 5)		64.2	15,431.5	24.2	19,637.1	
7	2013 Board-approved number of Customers at December		323,287.0	2,064.0	1,067,757.0	6,778.0	1,399,886.0
	Base Rates						
8	Annual Volume Impact (10^3m^3)	(1)	39,588	41,294	114,193	126,241	321,316
9	2021 Net Annual Average Delivery Rate ($/m3)	(2)	$0.087	$0.053	$0.037	$0.034	
10	2021 Net Annual Average Storage Rate ($/m3)	(3)	$0.047	$0.034	$0.008	$0.007	
11	Delivery Rate Annual Balance Amount ($000)	(4)	$3,461	$2,168	$4,221	$4,255	$14,106
12	Storage Rate Annual Balance Amount ($000)	(4)	$1,873	$1,407	$916	$886	$5,081
	Y Factor Rates						
13	Annual Volume Impact (10^3m^3)	(1)	20,531	31,672	25,241	133,236	210,681
14	2021 Net Annual Average Delivery Rate ($/m3)	(2)	$0.006	$0.009	$0.013	$0.011	
15	2021 Net Annual Average Storage Rate ($/m3)	(3)	$0.000	$0.000	$0.000	$0.000	
16	Delivery Rate Annual Balance Amount ($000)	(4)	$133	$276	$317	$1,523	$2,249
17	Storage Rate Annual Balance Amount ($000)	(4)	$0	$0	$0	$0	$0
	Total Annual Balance Amounts ($000)						
18	Total Delivery Rate Annual Balance Amount (line 11+16)		$3,594	$2,444	$4,539	$5,779	$16,355.3
19	Total Storage Rate Annual Balance Amount (line 12+17)		$1,873	$1,407	$916	$886	$5,080.9
20	Storage Cost Annual Balance Amount ($000)		($201)	($99)	($890)	($1,249)	($2,438)
21	Interest ($000)	(5)	$64	$45	$65	$65	$239
22	Total Deferral Account Amounts ($000) (line 18+19+20+21)		$5,330	$3,797	$4,629	$5,481	$19,237

Notes:
(1) The annual volume is obtained from a monthly calculation of approved customers and the monthly usage variance.
(2) The Net Annual Average Delivery Rate is the volume-weighted average of Board-approved monthly unit rates in effect
(3) The Net Annual Average Storage Rate is the volume-weighted average of Board-approved monthly unit rates in effect
(4) The annual revenue is obtained from a monthly calculation of volumes (lines 8 and 13) and the monthly unit delivery and storage rates (lines 9, 10, 14 and 15).
(5) Interest is calculated on the monthly opening balance in the deferral account in accordance with the methodology approved by the Board in EB-2006-0117. Interest is calculated to Dec 31, 2022.

CALCULATION OF 2021 TRANSPORTATION REVENUES ON THE LOBO D/BRIGHT C/DAWN H COMPRESSOR PROJECT COST DEFERRAL ACCOUNT
UNION RATE ZONES

Particulars	Volume (TJ/d) [1]	Revenue ($000's) [2]	Project Surplus Allocation (%)	Allocation ($000's)
	(a)	(b)	(a)	(d) = (b) x (c)
2021				
January	30	111	100%	111
February	30	111	100%	111
March	30	111	100%	111
April	30	111	100%	111
May	30	111	100%	111
June	30	111	100%	111
July	30	111	100%	111
August	30	111	100%	111
September	30	111	100%	111
October	30	111	100%	111
November	30	111	100%	111
December	30	111	100%	111
Total		1,337		1,337

Notes
(1) Capacity of 30,393 GJ/d assumed to be sold long term.
(2) Sold at the Dawn to Parkway M12 Rate of $3.665 $/GJ

ALLOCATION AND DISPOSITION OF 2021 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The purpose of this evidence is to address the allocation and disposition of 2021 deferral and variance account balances identified at Exhibit C, Tab 1, Schedule 1.

2. Enbridge Gas proposes to dispose of the approved 2021 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as January 1, 2023.

3. This exhibit of evidence is organized as follows:
    1. Allocation of Deferral and Variance Accounts
        - 1.1 EGI Accounts
        - 1.2 EGD Rate Zone Accounts
        - 1.3 Union Rate Zones' Accounts
    2. Disposition of Deferral and Variance Accounts
    3. General Service Bill Impacts

1. Allocation of Deferral and Variance Accounts

4. In accordance with the OEB's EB-2017-0306/EB-2017-0307 Decision and Order (MAADs Decision), the OEB approved new EGI deferral and variance accounts that apply to both the EGD rate zone and Union rate zones effective January 1, 2019. The applicability of other deferral and variance accounts that were approved to continue during the deferred rebasing period is for either the EGD rate zone or the Union rate zones.

1.1. EGI Accounts

5. The OEB previously approved[1] the following deferral and variance accounts for Enbridge Gas that are applicable to both the EGD and Union rate zones:
    - Accounting Policy Changes Deferral Account (APCDA),
    - Earnings Sharing Mechanism Deferral Account (ESMDA),
    - Tax Variance Deferral Account (TVDA),
    - Expansion of Natural Gas Distribution System Variance Account (ENGDSVA),
    - IRP Operating Costs Deferral Account,
    - IRP Capital Costs Deferral Account, and
    - Impacts Arising from the COVID-19 Emergency Deferral Account (IACEDA).

6. Enbridge Gas is proposing to dispose of the 2021 balance in the TVDA and the IRP Operating Costs Deferral Account as part of this application. The balance in the APCDA and IACEDA are not proposed for disposition as part of this application, as described at Exhibit C, Tab 1. There is no balance for the ESMDA, ENGDSVA and IRP Capital Costs Deferral Account, as shown at Exhibit C, Tab 1, Schedule 1.

7. The 2021 TVDA balance, including interest, is a credit of $19.390 million as shown at Exhibit C, Tab 1, Schedule 1. Consistent with the methodology approved by the OEB in previous years, Enbridge Gas has split the credit balance of $19.390 million between the EGD and Union rate zones in proportion to the 2018 actual rate base for each rate zone.[2] Splitting the $19.390 million TVDA credit balance in proportion to 2018 actual rate base results in a credit of $10.236 million being cleared to the EGD rate zone and a credit of $9.154 million being cleared to the Union rate zones. The details of the split to rate zones is provided at Exhibit F, Tab 1, Schedule 1.

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[1] EB-2017-0306/EB-2017-0307 Decision and Order established the APCDA, ESMDA and TVDA. The ENGDSVA was established in accordance with Section 4 of Ontario Regulation 24/19. The IRP Operating Costs Deferral Account and the IRP Capital Costs Deferral Account were established in accordance with the EB-2020-0091 Decision and Order.
[2] EB-2020-0134 Decision and Order, May 6, 2021, page 16.

8. The 2021 IRP Operating Cost Deferral Account balance, including interest, is a debit of $0.058 million as shown at Exhibit C, Tab 1, Schedule 1. Consistent with the TVDA, Enbridge Gas has split the debit balance of $0.058 million between the EGD and Union rate zones in proportion to the 2018 actual rate base for each rate zone.[3] Splitting the $0.058 million debit balance in proportion to 2018 actual rate base results in a debit of $0.031 million being cleared to the EGD rate zone and a debit of $0.027 million being cleared to the Union rate zones. The details of the split to rate zones is provided at Exhibit F, Tab 1, Schedule 1.

9. Enbridge Gas has allocated the split balance of the TVDA and IRP Operating Cost Deferral Account to rate classes in each rate zone in proportion to 2018 rate base for the EGD rate zone and 2013 rate base for the Union rate zones. The rate base allocation for each rate zone is taken from the last fully allocated cost study prepared for each rate zone. The allocation to EGD rate classes is provided at Exhibit F, Tab 2, Schedule 3. The allocation to Union rate classes is provided at Exhibit F, Tab 3, Schedule 2.

1.2 EGD Rate Zone Accounts

10. The 2021 deferral and variance account balances to be cleared to the EGD rate zone are provided at Exhibit F, Tab 2, Schedule 2, including the EGD rate zone allocation of the EGI accounts.

11. The 2021 EGD rate zone deferral and variance account balances are allocated to the customer classes using the same methodologies that the OEB approved in previous years.

12. The allocation of account balances to EGD rate classes based on cost drivers for each type of account is provided at Exhibit F, Tab 2, Schedule 3. A summary of the

[3] EB-2020-0134 Decision and Order, May 6, 2021, page 16.

allocation of account balances by rate class and type of service is provided at Exhibit F, Tab 2, Schedule 4.

1.3 Union Rate Zones' Accounts

13. The 2021 deferral and variance account balances to be cleared to the Union rate zones are provided at Exhibit F, Tab 3, Schedule 1, including the Union rate zones allocation of the EGI accounts.

14. The 2021 Union rate zones' deferral and variance account balances are allocated to the customer classes using the same methodologies that the OEB approved in previous years except for the Deferral Clearing Variance Account (179-132) in the Union rate zone.

15. With the harmonization of Enbridge Gas's customer information system (CIS) in 2021, the Union rate zone is no longer able to identify and allocate DCVA balances to rate classes. Consistent with the EGD rate zone Deferred Rebate Account allocation, Enbridge Gas proposes to split the DCVA balance between general service and contract customers. The allocation of general service and contract customer balances to rate classes is based on respective volumes. Please refer to Exhibit E, Tab 1 for background on the DCVA balance, and Exhibit F, Tab 3, Schedule 3 for the proposed allocation.

16. The allocation of account balances to Union South and Union North rate classes is provided at Exhibit F, Tab 3, Schedule 2.

2. Disposition of Deferral and Variance Accounts

17. Enbridge Gas proposes to dispose of the approved 2021 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as January 1, 2023

18. Enbridge Gas proposes to dispose of the 2021 deferral and variance account balances as a one-time billing adjustment. The billing adjustment will appear as a separate line item on customers' bills, the earliest being January 2023. The one-time billing adjustment will be derived for each customer by applying the disposition unit rates to each customer's actual consumption volume or contract demand, as applicable, for the period January 1, 2021 to December 31, 2021.

19. The unit rates for disposition by rate class and service type are provided at Exhibit F, Tab 2, Schedule 1 and Schedule 5 for the EGD rate zone. The unit rates for disposition for the Union rate zones, including a summary of the balances to be disposed of to ex-franchise rate classes are provided at Exhibit F, Tab 3, Schedule 4.

3. General Service Bill Impacts

20. For a Rate 1 sales service and western t-service customer in the EGD rate zone with annual consumption of 2,400 m^3, the one-time billing adjustment charge is $5.01.[4] /u

21. For a Rate M1 sales service residential customer in Union South with annual consumption of 2,200 m^3, the one-time billing adjustment charge is $9.34. For a Rate M1 bundled direct purchase (DP) residential customer, the one-time billing adjustment charge is $1.91. /u

22. For a Rate 01 sales service and bundled DP residential customer in Union North West with annual consumption of 2,200 m^3, the one-time billing adjustment credit is $17.33. /u

[4] In addition to the EGD rate zone 2021 Deferral bill impacts, the allocation of Union rate zone deferrals to Rate M12 results in a bill impact of approximately $1.00 to a typical Rate 1 residential customer in the EGD rate zone.

23. For a Rate 01 sales service and bundled DP residential customer in Union North East with annual consumption of 2,200 m^3, the one-time billing adjustment charge is $7.78. /u

24. Bill impacts of the proposed disposition are provided at Exhibit F, Tab 2, Schedule 6 for the EGD rate zone and Exhibit F, Tab 3, Schedule 5 for the Union rate zones.

ENBRIDGE GAS INC.
Split of EGI Account Balances to Rate Zones

Line No.	Particulars ($ millions)	Allocator: 2018 Actual Rate Base (1)	Account Balance: Principal (2)	Account Balance: Interest (2)	Account Balance: Total
		(a)	(b)	(c)	(d) = (b+c)
	2021 Tax Variance Deferral Account				
1	EGD rate zone	6,729	(10.116)	(0.120)	(10.236)
2	Union rate zones	6,018	(9.047)	(0.107)	(9.154)
3	Total	12,748	(19.163)	(0.227)	(19.390)
	2021 IRP Operating Costs Deferral Account				
4	EGD	6,729	0.030	0.000	0.031
5	Union	6,018	0.027	0.000	0.027
6	Total	12,748	0.058	0.000	0.058

Note:
(1) 2018 actual rate base per EB-2019-0105, Exhibit B, Tab 2, Appendix B, Schedule 1 for the EGD rate zone and EB-2019-0105, Exhibit C, Tab 2, Appendix A, Schedule 4 for the Union rate zones.
(2) Allocated in proportion to column (a).

ENBRIDGE GAS INC.
EGD RATE ZONE
UNIT RATE AND TYPE OF SERVICE: CLEARING IN JANUARY 2023

		COL.1
		UNIT RATE (¢/m³)
Bundled Services:		
RATE 1	- SYSTEM SALES	0.2086
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.2572
	- DAWN T-SERVICE	0.2572
	- WESTERN T-SERVICE	0.2086
RATE 6	- SYSTEM SALES	0.2527
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.3013
	- DAWN T-SERVICE	0.3013
	- WESTERN T-SERVICE	0.2527
RATE 9	- SYSTEM SALES	0.0151
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.0000
	- WESTERN T-SERVICE	0.0000
RATE 100	- SYSTEM SALES	0.0675
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1160
	- DAWN T-SERVICE	0.1160
	- WESTERN T-SERVICE	0.0000
RATE 110	- SYSTEM SALES	0.0209
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0694
	- DAWN T-SERVICE	0.0694
	- WESTERN T-SERVICE	0.0209
RATE 115	- SYSTEM SALES	0.0127
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0613
	- DAWN T-SERVICE	0.0613
	- WESTERN T-SERVICE	0.0000
RATE 135	- SYSTEM SALES	0.0123
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.0609
	- WESTERN T-SERVICE	0.0123
RATE 145	- SYSTEM SALES	0.0000
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.0734
	- WESTERN T-SERVICE	0.0000
RATE 170	- SYSTEM SALES	0.0200
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0685
	- DAWN T-SERVICE	0.0685
	- WESTERN T-SERVICE	0.0000
RATE 200	- SYSTEM SALES	0.0607
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1092
	- DAWN T-SERVICE	0.1092
	- WESTERN T-SERVICE	0.0000
Unbundled Services (Billing based on CD):		
RATE 125	- All	(0.3318)
RATE 300	- All	(1.5672)
RATE 332	- All	(0.3320)

ENBRIDGE GAS INC.
EGD RATE ZONE
DETERMINATION OF BALANCES TO BE CLEARED FROM THE 2021 DEFERRAL AND VARIANCE ACCOUNTS

ITEM NO.		COL. 1 PRINCIPAL FOR CLEARING ($000)	COL. 2 INTEREST ($000)	COL. 3 TOTAL FOR CLEARING ($000)
EGD RATE ZONE				
1.	TRANSACTIONAL SERVICES D/A	(3,904.1)	(35.4)	(3,939.6)
2.	UNACCOUNTED FOR GAS V/A	753.9	4.5	758.4
3.	STORAGE AND TRANSPORTATION D/A	7,942.5	97.0	8,039.5
4.	DEFERRED REBATE ACCOUNT	4,359.4	53.5	4,412.9
5.	OEB COST ASSESSMENT VARIANCE ACCOUNT	2,550.3	31.5	2,581.8
6.	AVERAGE USE TRUE-UP V/A	14,934.3	135.5	15,069.8
7.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8	-	4,435.8
8.	DAWN ACCESS COSTS D/A	1,968.0	17.9	1,985.9
9.	EGD RATE ZONE SUB-TOTAL	33,040.0	304.5	33,344.6
EGI ACCOUNTS				
10.	TAX VARIANCE - ACCELERATED CCA - EGD RATE ZONE PORTION	(10,115.6)	(119.9)	(10,235.5)
11.	IRP OPERATING COST DEFERRAL ACCOUNT - EGD RATE ZONE PORTION	30.5	0.3	30.7
12.	EGI SUB-TOTAL	(10,085.1)	(119.7)	(10,204.8)
13.	TOTAL	22,954.9	184.9	23,139.8

ENBRIDGE GAS INC.

EGD RATE ZONE

CLASSIFICATION AND ALLOCATION OF DEFERRAL AND VARIANCE ACCOUNT BALANCES

ITEM NO.		COL.1 TOTAL	COL. 2 SALES AND WBT	COL. 3 TOTAL SALES	COL. 4 TOTAL DELIVERIES	COL. 5 SPACE	COL. 6 DELIVE-RABILITY	COL. 7 DIRECT	COL. 8 NUMBER OF CUSTOMERS	COL. 9 RATE BASE	COL. 10 BUNDLED ANNUAL DELIVERIES
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
	CLASSIFICATION										
1.	TRANSACTIONAL SERVICES D/A	(3,939.6)	(3,792.2)			(50.2)	(97.2)				
2.	UNACCOUNTED FOR GAS V/A	758.4			758.4						
3.	STORAGE AND TRANSPORTATION D/A	8,039.5				2,736.9	5,302.6				
4.	DEFERRED REBATE ACCOUNT	4,412.9			4,412.9						
5.	OEB COST ASSESSMENT VARIANCE ACCOUNT	2,581.8								2,581.8	
6.	TAX VARIANCE - ACCELERATED CCA - EGI	(10,235.5)								(10,235.5)	
7.	AVERAGE USE TRUE-UP V/A	15,069.8						15,069.8			
8.	IRP OPERATING COST DEFERRAL ACCOUNT - EGI	30.7								30.7	
9.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8								4,435.8	
10.	DAWN ACCESS COSTS D/A	1,985.9									1,985.9
	TOTAL	23,139.8	(3,792.2)	0.0	5,171.3	2,686.7	5,205.4	15,069.8	0.0	(3,187.2)	1,985.9
	ALLOCATION										
1.1	RATE 1	9,940.8	(2,270.6)	0.0	2,183.6	1,286.9	2,859.2	7,134.0	0.0	(2,090.8)	838.5
1.2	RATE 6	11,974.2	(1,397.3)	0.0	2,040.9	1,233.1	2,263.7	7,935.8	0.0	(885.7)	783.7
1.3	RATE 9	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.4	RATE 100	33.2	(6.3)	0.0	15.6	7.3	17.3	0.0	0.0	(6.8)	6.0
1.5	RATE 110	718.7	(46.3)	0.0	506.7	89.8	12.1	0.0	0.0	(38.3)	194.6
1.6	RATE 115	237.1	(0.5)	0.0	178.3	0.0	4.8	0.0	0.0	(14.0)	68.5
1.7	RATE 125	(30.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(30.7)	0.0
1.8	RATE 135	37.0	(1.4)	0.0	29.0	0.0	0.0	0.0	0.0	(1.8)	11.1
1.9	RATE 145	18.2	0.0	0.0	11.4	5.6	0.0	0.0	0.0	(3.1)	4.4
1.10	RATE 170	172.2	(3.1)	0.0	117.6	16.9	0.0	0.0	0.0	(4.4)	45.2
1.11	RATE 200	142.8	(66.9)	0.0	88.3	47.2	48.2	0.0	0.0	(8.0)	33.9
1.12	RATE 300	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)	0.0
1.13	RATE 332	(103.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(103.4)	0.0
		23,139.8	(3,792.2)	0.0	5,171.3	2,686.7	5,205.4	15,069.8	0.0	(3,187.2)	1,985.9

ENBRIDGE GAS INC.
EGD RATE ZONE
ALLOCATION BY TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	BUNDLED ANNUAL DELIVERIES
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:											
RATE 1	- SYSTEM SALES	9,734.6	(2,264.0)	-	2,145.5	1,264.5	2,809.3	7,009.7	-	(2,054.3)	823.9
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	0.1	-	-	0.0	0.0	0.0	0.1	-	(0.0)	0.0
	- DAWN T-SERVICE	177.9	-	-	31.8	18.7	41.6	103.9	-	(30.5)	12.2
	- WBT	28.2	(6.6)	-	6.2	3.7	8.1	20.3	-	(5.9)	2.4
RATE 6	- SYSTEM SALES	6,925.4	(1,329.6)	-	1,260.0	761.2	1,397.5	4,899.2	-	(546.8)	483.8
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	137.6	-	-	21.0	12.7	23.3	81.7	-	(9.1)	8.1
	- DAWN T-SERVICE	4,558.4	-	-	695.7	420.4	771.7	2,705.4	-	(301.9)	267.2
	- WBT	352.8	(67.7)	-	64.2	38.8	71.2	249.6	-	(27.9)	24.6
RATE 9	- SYSTEM SALES	0.0	(0.0)	-	0.0	0.0	-	-	-	-	0.0
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	-	-	-	-	-	-	-	-	-	-
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 100	- SYSTEM SALES	8.7	(6.3)	-	5.9	2.8	6.6	-	-	(2.6)	2.3
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	1.9	-	-	0.7	0.3	0.8	-	-	(0.3)	0.3
	- DAWN T-SERVICE	22.6	-	-	9.0	4.2	9.9	-	-	(3.9)	3.4
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 110	- SYSTEM SALES	17.4	(40.4)	-	38.3	6.8	0.9	-	-	(2.9)	14.7
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	39.5	-	-	26.2	4.6	0.6	-	-	(2.0)	10.1
	- DAWN T-SERVICE	659.2	-	-	436.6	77.4	10.5	-	-	(33.0)	167.7
	- WBT	2.5	(5.9)	-	5.6	1.0	0.1	-	-	(0.4)	2.1
RATE 115	- SYSTEM SALES	0.1	(0.5)	-	0.5	0.0	0.0	-	-	(0.0)	0.2
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	81.1	-	-	60.9	0.0	1.7	-	-	(4.8)	23.4
	- DAWN T-SERVICE	155.8	-	-	116.9	0.0	3.2	-	-	(9.2)	44.9
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 135	- SYSTEM SALES	0.3	(1.3)	-	1.2	-	-	-	-	(0.1)	0.5
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	36.7	-	-	27.7	-	-	-	-	(1.7)	10.6
	- WBT	0.0	(0.1)	-	0.1	-	-	-	-	(0.0)	0.0
RATE 145	- SYSTEM SALES	-	-	-	-	-	-	-	-	-	-
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	18.2	-	-	11.4	5.6	-	-	-	(3.1)	4.4
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 170	- SYSTEM SALES	1.3	(3.1)	-	2.9	0.4	-	-	-	(0.1)	1.1
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	99.4	-	-	66.7	9.6	-	-	-	(2.5)	25.6
	- DAWN T-SERVICE	71.5	-	-	48.0	6.9	-	-	-	(1.8)	18.4
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 200	- SYSTEM SALES	83.6	(66.9)	-	63.4	33.9	34.6	-	-	(5.7)	24.3
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	2.0	-	-	0.9	0.5	0.5	-	-	(0.1)	0.3
	- DAWN T-SERVICE	57.2	-	-	24.1	12.9	13.2	-	-	(2.2)	9.2
	- WBT	-	-	-	-	-	-	-	-	-	-
Unbundled Services: (Billing based on CD)											
RATE 125		(30.7)	-	-	-	-	-	-	-	(30.7)	-
RATE 300		(0.2)	-	-	-	-	-	-	-	(0.2)	-
RATE 332		(103.4)	-	-	-	-	-	-	-	(103.4)	-
		23,139.8	(3,792.2)	0.0	5,171.3	2,686.7	5,205.4	15,069.8	0.0	(3,187.2)	1,985.9

ENBRIDGE GAS INC.
EGD RATE ZONE
UNIT RATE BY TYPE OF SERVICE*

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	BUNDLED ANNUAL DELIVERIES
		(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)
Bundled Services:											
RATE 1	- SYSTEM SALES	0.2086	(0.0485)	0.0000	0.0460	0.0271	0.0602	0.1502	0.0000	(0.0440)	0.0177
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.2572	0.0000	0.0000	0.0460	0.0271	0.0602	0.1502	0.0000	(0.0440)	0.0177
	- DAWN T-SERVICE	0.2572	0.0000	0.0000	0.0460	0.0271	0.0602	0.1502	0.0000	(0.0440)	0.0177
	- WESTERN T-SERVICE	0.2086	(0.0485)	0.0000	0.0460	0.0271	0.0602	0.1502	0.0000	(0.0440)	0.0177
RATE 6	- SYSTEM SALES	0.2527	(0.0485)	0.0000	0.0460	0.0278	0.0510	0.1788	0.0000	(0.0200)	0.0177
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.3013	0.0000	0.0000	0.0460	0.0278	0.0510	0.1788	0.0000	(0.0200)	0.0177
	- DAWN T-SERVICE	0.3013	0.0000	0.0000	0.0460	0.0278	0.0510	0.1788	0.0000	(0.0200)	0.0177
	- WESTERN T-SERVICE	0.2527	(0.0485)	0.0000	0.0460	0.0278	0.0510	0.1788	0.0000	(0.0200)	0.0177
RATE 9	- SYSTEM SALES	0.0151	(0.0485)	0.0000	0.0460	0.0000	0.0000	0.0000	0.0000	0.0000	0.0177
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	0.0675	(0.0485)	0.0000	0.0460	0.0213	0.0510	0.0000	0.0000	(0.0200)	0.0177
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1160	0.0000	0.0000	0.0460	0.0213	0.0510	0.0000	0.0000	(0.0200)	0.0177
	- DAWN T-SERVICE	0.1160	0.0000	0.0000	0.0460	0.0213	0.0510	0.0000	0.0000	(0.0200)	0.0177
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 110	- SYSTEM SALES	0.0209	(0.0485)	0.0000	0.0460	0.0082	0.0011	0.0000	0.0000	(0.0035)	0.0177
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0694	0.0000	0.0000	0.0460	0.0082	0.0011	0.0000	0.0000	(0.0035)	0.0177
	- DAWN T-SERVICE	0.0694	0.0000	0.0000	0.0460	0.0082	0.0011	0.0000	0.0000	(0.0035)	0.0177
	- WESTERN T-SERVICE	0.0209	(0.0485)	0.0000	0.0460	0.0082	0.0011	0.0000	0.0000	(0.0035)	0.0177
RATE 115	- SYSTEM SALES	0.0127	(0.0485)	0.0000	0.0460	0.0000	0.0012	0.0000	0.0000	(0.0036)	0.0177
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0613	0.0000	0.0000	0.0460	0.0000	0.0012	0.0000	0.0000	(0.0036)	0.0177
	- DAWN T-SERVICE	0.0613	0.0000	0.0000	0.0460	0.0000	0.0012	0.0000	0.0000	(0.0036)	0.0177
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 135	- SYSTEM SALES	0.0123	(0.0485)	0.0000	0.0460	0.0000	0.0000	0.0000	0.0000	(0.0028)	0.0177
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.0609	0.0000	0.0000	0.0460	0.0000	0.0000	0.0000	0.0000	(0.0028)	0.0177
	- WESTERN T-SERVICE	0.0123	(0.0485)	0.0000	0.0460	0.0000	0.0000	0.0000	0.0000	(0.0028)	0.0177
RATE 145	- SYSTEM SALES	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.0734	0.0000	0.0000	0.0460	0.0224	0.0000	0.0000	0.0000	(0.0127)	0.0177
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 170	- SYSTEM SALES	0.0200	(0.0485)	0.0000	0.0460	0.0066	0.0000	0.0000	0.0000	(0.0017)	0.0177
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0685	0.0000	0.0000	0.0460	0.0066	0.0000	0.0000	0.0000	(0.0017)	0.0177
	- DAWN T-SERVICE	0.0685	0.0000	0.0000	0.0460	0.0066	0.0000	0.0000	0.0000	(0.0017)	0.0177
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 200	- SYSTEM SALES	0.0607	(0.0485)	0.0000	0.0460	0.0246	0.0251	0.0000	0.0000	(0.0042)	0.0177
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1092	0.0000	0.0000	0.0460	0.0246	0.0251	0.0000	0.0000	(0.0042)	0.0177
	- DAWN T-SERVICE	0.1092	0.0000	0.0000	0.0460	0.0246	0.0251	0.0000	0.0000	(0.0042)	0.0177
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unbundled Services (Billing based on CD, ¢/m3):											
RATE 125	- All	(0.3318)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(0.3318)	0.0000
	- Customer-specific **										
RATE 300	- All	(1.5672)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(1.5672)	0.0000
	- Customer-specific **										
RATE 332	- All	(0.3320)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(0.3320)	0.0000

Notes:

* Unit Rates derived based on 2021 actual volumes

ENBRIDGE GAS INC.
EGD RATE ZONE
2021 DEFERRAL AND VARIANCE ACCOUNT CLEARING
BILL ADJUSTMENT IN JANUARY 2023 FOR TYPICAL CUSTOMERS

ITEM NO.	COL. 1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
			UNIT RATE				BILL ADJUSTMENT			
	GENERAL SERVICE	ANNUAL VOLUME m^3	SALES (¢/m^3)	ONTARIO TS (¢/m^3)	DAWN TS (¢/m^3)	WESTERN TS (¢/m^3)	SALES CUSTOMERS ($)	ONTARIO TS CUSTOMERS ($)	DAWN TS CUSTOMERS ($)	WESTERN TS CUSTOMERS ($)
1.1	**RATE 1 RESIDENTIAL**									
1.2	Heating & Water Heating	2,400	0.2086	0.2572	0.2572	0.2086	5.01	6.17	6.17	5.01
2.1	**RATE 6 COMMERCIAL**									
2.2	Heating & Other Uses	22,606	0.2527	0.3013	0.3013	0.2527	57.14	68.10	68.10	57.14
2.3	General Use	43,285	0.2527	0.3013	0.3013	0.2527	109.40	130.40	130.40	109.40
	CONTRACT SERVICE									
3.1	**RATE 100**									
3.2	Industrial - small size	339,188	0.0675	0.1160	0.1160	0.0000	228.93	393.51	393.51	-
4.1	**RATE 110**									
4.2	Industrial - small size, 50% LF	598,568	0.0209	0.0694	0.0694	0.0209	125.09	415.53	415.53	125.09
4.3	Industrial - avg. size, 75% LF	9,976,121	0.0209	0.0694	0.0694	0.0209	2,084.82	6,925.45	6,925.45	2,084.82
5.1	**RATE 115**									
5.2	Industrial - small size, 80% LF	4,471,609	0.0127	0.0613	0.0613	0.0000	570.01	2,739.73	2,739.73	-
6.1	**RATE 135**									
6.2	Industrial - Seasonal Firm	598,567	0.0123	0.0000	0.0609	0.0123	73.83	-	364.26	73.83
7.1	**RATE 145**									
7.2	Commercial - avg. size	598,568	0.0000	0.0000	0.0734	0.0000	-	-	439.29	-
8.1	**RATE 170**									
8.2	Industrial - avg. size, 75% LF	9,976,121	0.0200	0.0685	0.0685	0.0000	1,996.70	6,837.33	6,837.33	-

Notes:
Col. 7 = Col. 2 x Col. 3
Col. 8 = Col. 2 x Col. 4
Col. 9 = Col. 2 x Col. 5
Col. 10 = Col. 2 x Col. 6

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rate and Type of Service
2021 Deferral Account Disposition

Line No.	Particulars	Sales/System Gas Unit Rate for Billing Unit Rate (cents/m^3)	Bundled T-Service Unit Rate for Billing Unit Rate (cents/m^3)	T-Service Unit Rate for Billing Unit Rate (cents/m^3)
		(a)	(b)	(c)
	Union North West			
1	Rate 01	(0.7877)	(0.7877)	0.4169
2	Rate 10	0.3313	0.3313	1.1667
3	Rate 20	(4.9363)	(4.9363)	(0.0106)
4	Rate 25	0.1585	0.1585	(0.0167)
5	Rate 100	(0.0159)	(0.0159)	(0.0159)
	Union North East			
6	Rate 01	0.3537	0.3537	0.4169
7	Rate 10	1.1092	1.1092	1.1667
8	Rate 20	(0.9102)	(0.9102)	(0.0106)
9	Rate 25	(0.0549)	(0.0549)	(0.0167)
10	Rate 100	(0.0159)	(0.0159)	(0.0159)
	Union South			
11	Rate M1	0.7547	0.4169	-
12	Rate M2	1.5045	1.1667	-
13	Rate M4	0.4193	0.0815	-
14	Rate M5	0.2270	(0.1108)	-
15	Rate M7	0.4564	0.1186	-
16	Rate M9	0.4673	0.1295	-
17	Rate M10	0.3250	(0.0128)	-
18	Rate T1	-	-	0.0202
19	Rate T2	-	-	0.0420
20	Rate T3	-	-	0.0958

ENBRIDGE GAS INC.
Union Rate Zones
2021 Deferral Account Balances To Be Cleared
Year Ending December 31, 2021

Line No.	Account Number	Account Name ($000's)	Balance (a)	Interest (b)	Total (c)
1	179-131	Upstream Transportation Optimization	8,616	78	8,695
2	179-107	Spot Gas Variance Account	-	-	-
3	179-108	Unabsorbed Demand Costs Variance Account	(1,666)	(28)	(1,694)
4	179-153	Base Service North T-Service TransCanada Capacity	84	1	84
5	179-070	Short-Term Storage and Other Balancing Services	3,577	32	3,609
6	179-133	Normalized Average Consumption	18,997	239	19,237
7	179-132	Deferral Clearing Variance Account	(3,120)	(45)	(3,166)
8	179-151	OEB Cost Assessment Variance Account	907	11	919
9	179-103	Unbundled Services Unauthorized Storage Overrun	-	-	-
10	179-112	Gas Distribution Access Rule Costs	-	-	-
11	179-123	Conservation Demand Management	-	-	-
12	179-136	Parkway West Project Costs	(603)	(6)	(610)
13	179-137	Brantford-Kirkwall/Parkway D Project Costs	(45)	(0)	(45)
14	179-142	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	24	0	24
15	179-144	Lobo D/Bright C/Dawn H Compressor Project Costs	(112)	(4)	(116)
16	179-149	Burlington-Oakville Project Costs	(51)	(1)	(52)
17	179-156	Panhandle Reinforcement Project Costs	(3,162)	(36)	(3,198)
18	179-162	Sudbury Replacement Project	-	-	-
19	179-138	Parkway Obligation Rate Variance	-	-	-
20	179-143	Unauthorized Overrun Non-Compliance Account	-	-	-
21	179-157	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential V/A	-	(1,346)	(1,346)
22	179-135	Unaccounted for Gas Volume Variance Account	20,501	177	20,678
23	179-141	Unaccounted for Gas Price Variance Account	3,358	32	3,390
24	**Total for Union Rate Zone Specific Accounts (Lines 1 through 23)**		47,305	(895)	46,411
25	179-382	Earnings Sharing (Union Rate Zone Portion)	-	-	-
26	179-383	Tax Variance - Accelerated CCA - (Union Rate Zone Portion)	(9,047)	(107)	(9,154)
27	179-385	IRP Operating Costs Deferral Account - (Union Rate Zone Portion)	27	0	27
28	179-386	IRP Capital Costs Deferral Account	-	-	-
29	179-380	Expansion of Natural Gas Distribution Systems V/A (Union Rate Zone Portion)	-	-	-
30	**Total for EGI Accounts allocated to Union Rate Zone**		(9,020)	(107)	(9,127)
31	**Total Union Rate Zone Deferral Account Balances (Line 24 + Line 30)**		38,286	(1,002)	37,284

ENBRIDGE GAS INC.
Union Rate Zones
Classification and Allocation of Deferral and Variance Account Balances

			Union North					Union South																
Line No.	Particulars ($000's)	Acct No.	Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	M1	M2	M4	M5A	M7	M9	M10	T1	T2	T3	M12	M13	Excess Utility	C1	M16	M17	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)
	Gas Supply Related Deferrals:																							
1	Upstream Transportation Optimization	179-131	320	44	21	-	92	6,665	1,287	138	10	78	39	1	-	-	-	-	-	-	-	-	-	8,695
2	Spot Gas Variance Account	179-107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(3,908)	(762)	(168)	-	-	2,551	492	53	4	30	15	0	-	-	-	-	-	-	-	-	-	(1,694)
4	Base Service North T-Service TransCanada Capacity Account	179-153	-	-	57	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84
5	Total Gas Supply Related Deferrals		(3,588)	(718)	(90)	28	92	9,215	1,779	190	14	108	54	1	-	-	-	-	-	-	-	-	-	7,085
	Storage Related Deferrals:																							
6	Short-Term Storage and Other Balancing Services	179-70	493	139	76	2	-	1,124	424	190	2	106	20	0	81	859	92	-	-	-	-	-	-	3,609
	Delivery Related Deferrals:																							
7	Normalized Average Consumption (NAC)	179-133	5,330	3,797	-	-	-	4,629	5,481	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19,237
8	Deferral Clearing Variance Account - Delivery	179-132	(571)	(191)	4	6	1	(1,777)	(683)	4	0	5	1	0	3	31	2	-	-	-	-	-	-	(3,166)
9	OEB Cost Assessment Variance Account	179-151	184	16	14	12	6	464	43	16	18	5	1	0	12	33	4	86	0	3	2	0	-	919
10	Unbundled Services Unauthorized Storage Overrun	179-103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Gas Distribution Access Rule (GDAR) Costs	179-112	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Conservation Demand Management	179-123	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Parkway West Project Costs	179-136	4	(8)	(1)	2	1	103	4	3	3	0	(0)	0	4	19	(1)	(748)	0	1	3	0	-	(610)
14	Brantford-Kirkwall/Parkway D Project Costs	179-137	(7)	(1)	(1)	(1)	(0)	(16)	(3)	(1)	(1)	(0)	(0)	(0)	(1)	(2)	(0)	(11)	(0)	(0)	(0)	(0)	-	(45)
15	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	(40)	(2)	(4)	(4)	(2)	(150)	(20)	(7)	(5)	(2)	(0)	(0)	(6)	(30)	(2)	298	(0)	(1)	(1)	(0)	-	24
16	Lobo D/Bright C/ Dawn H Compressor Project Costs	179-144	(108)	(4)	(6)	(7)	(3)	(368)	(39)	(15)	(13)	(4)	(0)	(0)	(15)	(73)	(3)	559	(0)	(7)	(8)	(1)	-	(116)
17	Burlington-Oakville Project Costs	179-149	(3)	(1)	(0)	(0)	(0)	(25)	(8)	(2)	(0)	(1)	(0)	(0)	(2)	(13)	(2)	6	0	(0)	0	0	-	(52)
18	Panhandle Reinforcement Project Costs	179-156	(31)	(5)	(4)	(3)	(1)	(696)	(236)	(255)	(6)	(56)	(0)	(0)	(169)	(1,240)	(1)	(33)	(0)	(0)	(381)	(80)	-	(3,198)
19	Sudbury Replacement Project	179-162	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Parkway Obligation Rate Variance	179-138	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Unauthorized Overrun Non-Compliance Account	179-143	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Pension & OPEB Forecast Accrual vs Actual Cash Payment Differential Variance Account	179-157	(270)	(25)	(24)	(20)	(10)	(662)	(64)	(27)	(31)	(7)	(1)	(0)	(18)	(47)	(5)	(127)	(0)	(4)	(3)	(0)	-	(1,346)
23	Unaccounted for Gas (UFG) Volume Variance Account	179-135	328	109	50	-	21	2,178	837	459	48	516	68	0	295	2,848	202	9,393	23	-	3,131	162	10	20,678
24	Unaccounted for Gas (UFG) Price Variance Account	179-141	190	63	29	-	12	1,260	484	266	28	298	39	0	-	-	-	-	13	-	687	21	-	3,390
25	Tax Variance - Accelerated CCA - EGI	179-383	(1,627)	(251)	(178)	(137)	(49)	(3,553)	(538)	(134)	(114)	(47)	(9)	(0)	(93)	(410)	(54)	(1,888)	(1)	(53)	(17)	(2)	-	(9,154)
26	IRP Operating Costs Deferral Account - EGI	179-385	5	1	1	0	0	11	2	0	0	0	0	0	0	1	0	6	0	0	0	0	-	27
27	IRP Operating Costs Deferral Account - EGI	179-386	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Delivery-Related Deferrals		3,384	3,498	(120)	(152)	(24)	1,397	5,262	308	(72)	708	97	(0)	10	1,117	139	7,541	35	(61)	3,414	100	10	26,590
29	Total 2021 Storage and Delivery Disposition (Line 6 + Line 28)		3,877	3,638	(45)	(150)	(24)	2,522	5,686	498	(70)	814	117	(0)	91	1,977	231	7,541	35	(61)	3,414	100	10	30,199
30	Total 2021 Deferral Account Disposition (Line 5 + Line 29)		288	2,920	(134)	(122)	68	11,737	7,465	688	(57)	922	170	1	91	1,977	231	7,541	35	(61)	3,414	100	10	37,284
31	Earnings Sharing Deferral Account - EGI	179-382	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Grand Total (Line 30 + Line 31)		288	2,920	(134)	(122)	68	11,737	7,465	688	(57)	922	170	1	91	1,977	231	7,541	35	(61)	3,414	100	10	37,284

ENBRIDGE GAS INC.
Union Rate Zones
Allocation of 2021 Gas Supply Related Deferral Accounts by Union North East and Union North West

Line No.	Particulars ($000's)	Acct No.	Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (sum b:f)
	Union North West							
	Gas Supply Related Deferrals:							
1	Spot Gas Variance Account	179-107	-	-	-	-	-	-
2	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(3,883)	(756)	(167)	-	-	(4,806)
3	Upstream Transportation Optimization	179-131	716	175	80	-	100	1,072
4	Total Gas Supply Related Deferrals		(3,167)	(581)	(87)	-	100	(3,735)
	Storage Related Deferrals:							
5	Short-Term Storage and Other Balancing Services (1)	179-70	141	35	7	-	-	183
6	Total North West Deferral Account Disposition (Line 6 + Line 7)		(3,026)	(546)	(80)	-	100	(3,552)
	Union North East							
	Gas Supply Related Deferrals:							
7	Spot Gas Variance Account	179-107	-	-	-	-	-	-
8	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(25)	(6)	(1)	-	-	(32)
9	Upstream Transportation Optimization	179-131	(396)	(131)	(59)	-	(8)	(594)
10	Total Gas Supply Related Deferrals		(421)	(137)	(60)	-	(8)	(626)
	Storage Related Deferrals:							
11	Short-Term Storage and Other Balancing Services (1)	179-70	352	104	46	-	-	502
12	Total North East Deferral Account Disposition (Line 14 + Line 15)		(69)	(33)	(14)	-	(8)	(124)
	Total North							
	Gas Supply Related Deferrals:							
13	Spot Gas Variance Account	179-107	-	-	-	-	-	-
14	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(3,908)	(762)	(168)	-	-	(4,839)
15	Upstream Transportation Optimization	179-131	320	44	21	-	92	478
16	Total North Gas Supply Related Deferrals		(3,588)	(718)	(147)	-	92	(4,361)
	Storage Related Deferrals:							
17	Short-Term Storage and Other Balancing Services (1)	179-70	493	139	53	-	-	685
18	Total North Deferral Account Disposition (Line 22 + Line 23)		(3,095)	(579)	(94)	-	92	(3,676)

Notes:
(1) Excludes allocation to Rate 20/100 bundled storage service.

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rates for One-Time Adjustment - Delivery
2021 Deferral Account Disposition

Line No.	Particulars	Rate Class	2021 Deferral Balances ($000's)	2021 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2021 Actual Volume (10^3m^3)	Unit Rate ($cents/m^3$)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Union North						
1	Small Volume General Service	01	3,877	-	3,877	929,941	0.4169
2	Large Volume General Service	10	3,638	-	3,638	311,794	1.1667
3	Medium Volume Firm Service	20	(68)	-	(68)	637,600	(0.0106)
4	Large Volume High Load Factor	100	(152)	-	(152)	958,587	(0.0159)
5	Large Volume Interruptible	25	(24)	-	(24)	143,898	(0.0167)
	Union South						
6	Small Volume General Service	M1	2,522	-	2,522	2,897,087	0.0870
7	Large Volume General Service	M2	5,686	-	5,686	1,113,864	0.5105
8	Firm Com/Ind Contract	M4	498	-	498	610,808	0.0815
9	Interruptible Com/Ind Contract	M5	(70)	-	(70)	63,511	(0.1108)
10	Special Large Volume Contract	M7	814	-	814	686,353	0.1186
11	Large Wholesale	M9	117	-	117	90,096	0.1295
12	Small Wholesale	M10	(0)	-	(0)	320	(0.0128)
13	Contract Carriage Service	T1	91	-	91	453,007	0.0202
14	Contract Carriage Service	T2	1,977	-	1,977	4,700,474	0.0420
15	Contract Carriage- Wholesale	T3	231	-	231	241,187	0.0958

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rates for One-Time Adjustment - Gas Supply Commodity
2021 Deferral Account Disposition

Line No.	Particulars	Rate Class	2021 Deferral Balances ($000's)	2021 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2021 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
1	Small Volume General Service	M1	9,215	-	9,215	2,728,007	0.3378
2	Large Volume General Service	M2	1,779	-	1,779	526,743	0.3378
3	Firm Com/Ind Contract	M4	190	-	190	56,304	0.3378
4	Interruptible Com/Ind Contract	M5	14	-	14	4,043	0.3378
5	Special Large Volume Contract	M7	108	-	108	31,987	0.3378
6	Large Wholesale	M9	54	-	54	15,903	0.3378
7	Small Wholesale	M10	1	-	1	320	0.3378

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rates for One-Time Adjustment - Gas Supply Transportation and Bundled Storage
2021 Deferral Account Disposition

Line No.	Particulars	Rate Class	2021 Deferral Balances ($000's)	2021 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2021 Actual Volume/ Demand	Billing Units	Unit Volumetric/ Demand Rate (cents/m^3)
			(a)	(b)	(c) = (a + b)	(d)		(e) = (c / d) * 100
	Gas Supply Transportation Charges							
	Union North West							
1	Small Volume General Service	01	(3,167)	-	(3,167)	262,912	10^3m^3	(1.2045)
2	Large Volume General Service	10	(581)	-	(581)	69,572	10^3m^3	(0.8354)
3	Medium Volume Firm Service	20	(87)	-	(87)	1,764	$10^3m^3/d$	(4.9257)
4	Large Volume Interruptible	25	100	-	100	57,362	10^3m^3	0.1752
	Union North East							
5	Small Volume General Service	01	(421)	-	(421)	667,029	10^3m^3	(0.0632)
6	Large Volume General Service	10	(137)	-	(137)	238,396	10^3m^3	(0.0575)
7	Medium Volume Firm Service	20	(60)	-	(60)	6,630	$10^3m^3/d$	(0.8996)
8	Large Volume Interruptible	25	(8)	-	(8)	21,827	10^3m^3	(0.0382)
9	North T-Service Transportation from Dawn Base Service ($/GJ)	20T/100T	84	-	84	264,264	GJ/d	0.320
	Storage ($/GJ)							
10	Bundled-T Storage Service	20T/100T	25	-	25	141,504	GJ/d	0.179

ENBRIDGE GAS INC.
Union Rate Zones
Storage and Transportation Service Amounts for Disposition
2021 Deferral Account Disposition

Line No.	Particulars ($000's) (1)	Rate Class	2021 Deferral Balances	2021 Earnings Sharing Mechanism	Deferral Balance for Disposition
			(a)	(b)	(c) = (a + b)
1	Transportation	M12	7,541	-	7,541
2	Transportation of Locally Produced Gas	M13	35	-	35
3	Cross Franchise Transportation	C1	3,414	-	3,414
4	Storage and Transportation Services	M16	100	-	100
5	Transporation Service	M17	10		10

Notes:
(1)
Ex-franchise customer specific amounts determined using approved deferral account allocation methodologies.

ENBRIDGE GAS INC.
Union Rate Zones
Calculation of One-Time Adjustments for Typical General Service Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Volume (m^3) (1)	Bill Impact ($)
		(a)	(b)	(c) = (a x b) / 100
	Small Volume General Service			
	Rate M1 - Union South			
1	Delivery	0.0870	2,200	1.91
2	Commodity	0.3378	2,200	7.43
3	Sales Service Impact	0.4248		9.34
4	Direct Purchase Impact			1.91
	Rate 01 - Union North West			
5	Delivery	0.4169	2,200	9.17
6	Commodity	-	2,200	-
7	Transportation	(1.2045)	2,200	(26.50)
8	Sales Service Impact	(0.7877)		(17.33)
9	Bundled-T (Direct Purchase) Impact			(17.33)
	Rate 01 - Union North East			
10	Delivery	0.4169	2,200	9.17
11	Commodity	-	2,200	-
12	Transportation	(0.0632)	2,200	(1.39)
13	Sales Service Impact	0.3537		7.78
14	Bundled-T (Direct Purchase) Impact			7.78
	Large Volume General Service			
	Rate M2 - Union South			
15	Delivery	0.5105	73,000	372.65
16	Commodity	0.3378	73,000	246.60
17	Sales Service Impact	0.8483		619.25
18	Direct Purchase Impact			372.65
	Rate 10 - Union North West			
19	Delivery	1.1667	93,000	1,085.06
20	Commodity	-	93,000	-
21	Transportation	(0.8354)	93,000	(776.97)
22	Sales Service Impact	0.3313		308.09
23	Bundled-T (Direct Purchase) Impact			308.09
	Rate 10 - Union North East			
24	Delivery	1.1667	93,000	1,085.06
25	Commodity	-	93,000	-
26	Transportation	(0.0575)	93,000	(53.46)
27	Sales Service Impact	1.1092		1,031.60
28	Bundled-T (Direct Purchase) Impact			1,031.60

Notes:
(1) Average consumption, per customer, for the period January 1, 2021 to December 31, 2021.

ENBRIDGE GAS INC.
Union Rate Zones
Calculation of One-Time Adjustments for Typical Small and Large Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Billing Units (m^3)	Bill Impact ($) (1)
		(a)	(b)	(c)
	Union North			
	Small Rate 20 - Union North West			
1	Delivery	(0.0106)	3,000,000	(318)
2	Transportation	(4.9257)	14,000	(8,275)
3	Sales Service Impact	(4.9363)		(8,593)
4	Bundled-T (Direct Purchase) Impact			(8,593)
	Large Rate 20 - Union North West			
5	Delivery	(0.0106)	15,000,000	(1,590)
6	Transportation	(4.9257)	60,000	(35,465)
7	Sales Service Impact	(4.9363)		(37,055)
8	Bundled-T (Direct Purchase) Impact			(37,055)
	Small Rate 20 - Union North East			
9	Delivery	(0.0106)	3,000,000	(318)
10	Transportation	(0.8996)	14,000	(1,511)
11	Sales Service Impact	(0.9102)		(1,829)
12	Bundled-T (Direct Purchase) Impact			(1,829)
	Large Rate 20 - Union North East			
13	Delivery	(0.0106)	15,000,000	(1,590)
14	Transportation	(0.8996)	60,000	(6,477)
15	Sales Service Impact	(0.9102)		(8,067)
16	Bundled-T (Direct Purchase) Impact			(8,067)
	Average Rate 25 - Union North West			
17	Delivery	(0.0167)	2,275,000	(380)
18	Transportation	0.1752	2,275,000	3,985
19	Sales Service Impact	0.1585		3,605
20	Bundled-T (Direct Purchase) Impact			3,605
	Average Rate 25 - Union North East			
21	Delivery	(0.0167)	2,275,000	(380)
22	Transportation	(0.0382)	2,275,000	(869)
23	Sales Service Impact	(0.0549)		(1,249)
24	Bundled-T (Direct Purchase) Impact			(1,249)
	Small Rate 100			
25	T-Service (Direct Purchase) Impact	(0.0159)	27,000,000	(4,286)
	Large Rate 100			
26	T-Service (Direct Purchase) Impact	(0.0159)	240,000,000	(38,094)
	Union South			
	Small Rate M4			
27	Delivery	0.0815	875,000	713
28	Commodity	0.3378	875,000	2,956
29	Sales Service Impact	0.4193		3,669
30	Direct Purchase Impact			713
	Large Rate M4			
31	Delivery	0.0815	12,000,000	9,779
32	Commodity	0.3378	12,000,000	40,536
33	Sales Service Impact	0.4193		50,315
34	Direct Purchase Impact			9,779

Notes:
(1) Transportation bill impacts based on monthly demand (m^3/d).

ENBRIDGE GAS INC.
Union Rate Zones
Calculation of One-Time Adjustments for Typical Small and Large Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Billing Units (m^3)	Bill Impact ($) (1)
		(b)	(c)	(d)
	Union South (continued)			
	Small Rate M5 Interruptible			
1	Delivery	(0.1108)	825,000	(914)
2	Commodity	0.3378	825,000	2,787
3	Sales Service Impact	0.2270		1,873
4	Direct Purchase Impact			(914)
	Large Rate M5 Interruptible			
5	Delivery	(0.1108)	6,500,000	(7,200)
6	Commodity	0.3378	6,500,000	21,957
7	Sales Service Impact	0.2270		14,757
8	Direct Purchase Impact			(7,200)
	Small Rate M7			
9	Delivery	0.1186	36,000,000	42,695
10	Commodity	0.3378	36,000,000	121,609
11	Sales Service Impact	0.4564		164,304
12	Direct Purchase Impact			42,695
	Large Rate M7			
13	Delivery	0.1186	52,000,000	61,671
14	Commodity	0.3378	52,000,000	175,658
15	Sales Service Impact	0.4564		237,329
16	Direct Purchase Impact			61,671
	Small Rate M9			
17	Delivery	0.1295	6,950,000	9,002
18	Commodity	0.3378	6,950,000	23,477
19	Sales Service Impact	0.4673		32,480
20	Direct Purchase Impact			9,002
	Large Rate M9			
21	Delivery	0.1295	20,178,000	26,136
22	Commodity	0.3378	20,178,000	68,162
23	Sales Service Impact	0.4673		94,298
24	Direct Purchase Impact			26,136
	Rate M10			
25	Delivery	(0.0128)	94,500	(12)
26	Commodity	0.3378	94,500	319
27	Sales Service Impact	0.3250		307
28	Direct Purchase Impact			(12)
	Small Rate T1			
29	Direct Purchase Impact	0.0202	7,537,000	1,521
	Average Rate T1			
30	Direct Purchase Impact	0.0202	11,565,938	2,334
	Large Rate T1			
31	Direct Purchase Impact	0.0202	25,624,080	5,171
	Small Rate T2			
32	Direct Purchase Impact	0.0420	59,256,000	24,917
	Average Rate T2			
33	Direct Purchase Impact	0.0420	197,789,850	83,169
	Large Rate T2			
34	Direct Purchase Impact	0.0420	370,089,000	155,620
	Large Rate T3			
35	Direct Purchase Impact	0.0958	272,712,000	261,162

Notes:
(1) Transportation bill impacts based on monthly demand (m^3/d).

2021 SCORECARD RESULTS – ENBRIDGE GAS

1. The purpose of the scorecard is to measure and monitor performance over the deferred rebasing period. The scorecard is produced annually, with 2021 being the third presentation of the scorecard for the amalgamated utility. Within EB-2021-1049, the OEB found that scorecard provides valuable information during the deferral rebasing period and accepted Enbridge Gas's plans to improve the results of the two metrics that did not meet the performance standard in 2020. The OEB found that the 2024 rebasing proceeding is the appropriate time to review historical performance trends and consider customer implications prior to making any adjustments to the performance scorecard.

2. In 2019 and 2020 there was a positive performance trend for all but two metrics: Time to Reschedule a Missed Appointment (TRMA) and the Meter Reading Performance Metric (MRPM). In 2021 Enbridge Gas continued to demonstrate the positive performance trend for 16 out of 20 metrics. There continued to be challenges meeting the performance standard for TRMA and MRPM and in addition, Enbridge Gas did not meet the performance standard for Call Answering Service Levels (CASL) and Abandon Rate. The challenges meeting the target for two additional metrics is viewed as an anomaly as historically targets are exceeded for the metrics. Enbridge Gas continues to work to improve the results of all scorecard metrics through ongoing reporting of results, identifying the root cause for variances, and implementing initiatives targeting areas where improvement can be made.

3. Three of the four metrics that are below performance standard for 2021 were impacted by COVID-19 pandemic restrictions and the amalgamation of utility systems and processes. Enbridge Gas has developed plans and strategies to improve results and performance in each area.

4. The TRMA metric tracks the percentage of customers contacted to reschedule the work within two hours of the end of the original appointment time. The annual standard for TRMA is 100% and Enbridge Gas achieved 97.0% in 2021. This is consistent with prior year results which were 97.0% in 2019 and 97.3% in 2020. Efforts toward meeting the TRMA target of 100% are ongoing. A cross functional team meets regularly to review performance on this metric, to address issues, and to re-inforce training when necessary. Regional management teams meet monthly to drive performance as well. While Enbridge Gas acknowledges that promptly rescheduling missed appointments is an important part of achieving the SQR and customer service, attainment of a perfect 100% is not always possible. TRMA is the only Scorecard metric with a target of 100%; and does not allow for human error.

5. The 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% and Enbridge Gas achieved a level of 5.0% in 2021. The result for 2019 was 0.7% and 4.4% in 2020. Enbridge Gas has faced challenges meeting the target since 2019 for several reasons, including the decision of a key meter reading vendor to no longer provide meter reading service resulting in the need to onboard a new vendor. Since March 2020, the Covid pandemic has presented additional challenges including closed businesses, increased customer sensitivity to contact with meter readers, and access issues during periods of lockdown. In addition, extreme weather events such as freezing rain, flooding, and heavy snowfall limited the ability to travel to properties and read meters. The new vendor was also still transitioning and learning the business in addition to experiencing ongoing staffing challenges including resourcing issues and illness/absence due to Public Health isolation/quartine requirements. These challenges continued into 2021. Despite the ongoing efforts of Enbridge Gas to improve the performance standard, the MRPM target of 0.5% will be challenging due to sheer size and geographic

reach, especially when complicated by variables such as extreme weather. Enbridge Gas continues to work to meet the performance metric through a mitigation plan that includes various methods to attain reads including: meter reading partners increasing hiring, working additional hours and knocking on doors to obtain reads; customer outreach through social media, monthly emails and texts to customers asking them to submit a reading; requesting a reading from customers when they contact the call centre; and engaging the Enbridge Gas Quality Assurance team to review consecutive estimates.

6. The CASL metric measures the number of calls reaching the general inquiry number answered within 30 seconds divided by the number of calls received. The yearly performance standard for Call Answering Service Level is 75% with a minimum monthly standard of 40%. The 2021 result was 64.3%. The 2021 result is viewed as an anomaly and not consistent with historical performance of 79.0% in 2019 and 75.2% in 2020. In July 2021, EGI harmonized the two legacy utilities Customer Information Systems (CIS), which involved moving 1.6M customers and their associated data from one CIS system to the other. In addition, the telephony system (IVR) was changed. Several changes, both pre and post integration, resulted in an increase in call volumes. Calls ranged from questions about passwords and account numbers to complex and extended calls. Covid has also impacted the contact centres due to increased illness and absence. To improve performance on the CASL metric, Enbridge Gas has identified and implemented several initiatives including recruiting temporary employees to assist with high call volumes, a post integration review of telephony (IVR) to ensure customer experience and decrease wait times, and a review of contact centre and billing processes. Enbridge Gas is committed to providing excellent customer service to all customers and in doing so meeting the performance standard of answering 75% of calls within 30 seconds.

7. The measure Abandon Rate is the percentage of callers who hang up while waiting for a live operator. The annual standard is not to exceed 10%. The 2021 result was 16.0%. As with the CASL metric, the 2021 result is viewed as an anomaly with historical performance of 2.5% in 2019 and 5.4% in 2020, exceeding the performance standard. The Abandon Rate metric was also impacted by the integration of systems in 2021 and the Covid pandemic. The increase in call volumes and staffing issues due to illness resulted in an increase in wait times driving the increased abandon rate. The mitigation plans in place for CASL will assist with reducing the abandoned call metric to less than 10%.

8. The OEB has found that Enbridge Gas's 2024 rebasing proceeding is the appropriate time to review historical performance trends and consider the customer implications before making any adjustments to the performance scorecard.[1] Enbridge Gas will be proposing changes to the scorecard in that proceeding to the TRMA metric and the MRPM.

[1] EB-2021-0149, OEB Decision and Order, Enbridge Gas – 2020 DVA & Earning Sharing Proceeding (January 27, 2022), page 12.

EGI Scorecard 2021

#	Performance Measure	Target	Actual 2021	Actual 2020	Actual 2019
#	**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%	96.9%	98.9%	98.1%
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%	94.5%	98.8%	98.5%
3	**Telephone calls answered on time (call answering service level)** (# of calls answered within 30 seconds / # of calls received)	75.0%	64.3%	75.2%	79.0%
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%	100.0%	100.0%	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.'		384,858 manual checks completed as per QAP	427,524 manual checks completed as per QAP	429,386 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%	16.0%	5.4%	2.5%
7	**Time to Reschedule Missed Appointments** (% of rescheduled work within 2 hours of the end of the original appointment time)	100.0%	97.0%	97.3%	97.0%
	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%	5.0%	4.4%	0.7%
9	**% of Emergency Calls Responded within One Hour** (# of emergency calls responded within 60 minutes / # of emergency calls)	90.0%	95.2%	96.7%	96.7%
10	**Compression Reliability** % reliable for transmission compression		99.7%	99.7%	99.9%
11	**Damages per 1000 locate requests**		1.95	2.22	1.97
12	**Total Cost per Customer** ($ / Customer)		643.9	658.2	653.6
13	**Total Cost per km of Distribution Pipe** ($ / km of Distribution Pipe)		16639.6	16928.5	16735.4
	PUBLIC POLICY RESPONSIVENESS (Conservation & Demand Management & Connection of Renewable Generation)				
14	**Total Cumulative Cubic Meters of Natural Gas Saved (Net)** (Millions)				2075.9
	FINANCIAL PERFORMANCE (Financial Ratios)				
15	**Current Ratio** (Current Assets / Current Liabilities)		0.71	0.66	0.75
16	**Debt Ratio** (Total Debt / Total Assets)		0.41	0.40	0.40
17	**Debt to Equity Ratio** (Total Debt / Shareholders' Equity)		1.06	1.01	0.98
18	**Interest Coverage** (EBIT / Interest Charges)		2.55	2.34	2.53
19	**Financial Statement Return on Assets** (Net Income / Total Assets)		2.07%	1.97%	2.25%
20	**Financial Statement Return on Equity** (Net Income / Shareholders' Equity)		5.32%	4.96%	5.56%

INTEGRATED RESOURCE PLANNING

2021 Annual Report

Enbridge Gas Inc.
May 31, 2022

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1. Introduction:

This inaugural Enbridge Gas Inc. ("Enbridge Gas") 2021 IRP Annual Report (the "Report") encompasses the period from July 22, 2021, through December 31, 2021.[1] Where appropriate, Enbridge Gas has included information on relevant IRP-related activities subsequent to the end of the 2021. This Report has been filed per the Ontario Energy Board's ("OEB") Integrated Resource Planning ("IRP") Decision and Order (dated July 22, 2021) establishing an IRP Framework for Enbridge Gas (the "Framework"), where the OEB directed:

> "Enbridge Gas shall file an Annual IRP Report with the OEB as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, the proceeding in which it may seek disposition of balances in the IRP Costs deferral accounts.
>
> The OEB does not intend to approve the annual IRP report, but it could impact the OEB's findings on the disposition of amounts in the IRP Costs deferral accounts or inform future proceedings.
>
> The annual IRP report and the report from the IRP Technical Working Group are to be filed for information regardless of whether Enbridge Gas is seeking approval to clear any balances in the IRP Costs deferral accounts. The annual IRP report should include the following information:
>
> - A summary of IRP stakeholdering activities from the past year
> - A summary of IRP engagement or consultation activities with Indigenous peoples
> - Updates on IRP pilot projects underway
> - Updates on incorporating IRP into asset management planning
> - Updates on status of potential IRP Plans
> - Updates on status of approved IRP Plans, including details of adjustments made by Enbridge Gas
> - Annual and cumulative summaries of actual peak demand reductions/energy savings generated by each IRP Plan to-date, including comparisons to the initial forecast reduction/energy savings and the actual amount of expenditure on each IRP Plan to-date
> - The most recent results of Enbridge Gas's IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening or technical/economic evaluation resulted in no further assessment of IRPAs
> - A summary of best available information on demand-side IRPAs, including types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions
> - Efforts taken to explore the use of interruptible rates for meeting system needs, including how customers have been provided the opportunity to consider this option
> - Any other IRP-related matters established by the OEB."[2]

[1] Future IRP annual reports will include the full calendar year.

[2] EB-2020-0091, Decision and Order, Appendix A, p. 22

2. IRP Integration

The establishment of the Framework has allowed Enbridge Gas to commence formally integrating IRP into its existing planning practices. Accordingly, Enbridge Gas reviewed its distribution and transmission planning practices and implemented changes including, implementation of the OEB approved IRP assessment process, and stakeholder engagement activities. In addition, Enbridge Gas is expanding existing processes to enable the effective evaluation and implementation of IRP alternative[3] ("IRPA") pilot and non-pilot projects.

In support of these integration activities Enbridge Gas is guided by the Guiding Principles established by the OEB in the IRP Decision:

- "Reliability and safety – In considering IRPAs as part of system planning processes, Enbridge Gas's system design principles cannot be compromised, and the reliable and safe delivery of firm contracted peak period natural gas volumes to Enbridge Gas's customers must remain of paramount importance.
- Cost-effectiveness – IRPAs must be cost-effective (competitive) compared to traditional Facility Alternatives[4] and other IRPAs, including taking into account impacts on Enbridge Gas customers.
- Public policy – IRP will be considered in a manner to ensure that it is supportive of and aligned with public policy, and in particular the OEB's statutory objectives for the natural gas sector.
- Optimized scoping – Recognizing that reviewing IRPAs for every forecast infrastructure project would be extremely time intensive, binary screening should be undertaken, to confirm which forecast need(s) should undergo evaluation of IRPAs, and to ensure a focus at the outset on efficient and effective IRPA investment.
- Risk management – Economic risks associated with both Facility Alternatives and IRPAs in meeting system needs are evaluated and appropriately mitigated. Risks and rewards are allocated appropriately between Enbridge Gas and its customers."[5]

More detailed discussion of the steps towards IRP integration taken by Enbridge Gas follow:

<u>Stakeholder Engagement</u>

Stakeholder engagement activities are ongoing. Following the completion and filing of the Company's 2023-2032 Asset Management Plan ("AMP") in the fall of 2022, Enbridge Gas will commence IRP-related regional and geo-targeted stakeholder engagement. Stakeholder feedback received through these engagement activities will be reviewed and responded to (where appropriate) and will inform the Company's consideration and development of potential IRP projects as well as future AMPs. For

[3] The types of eligible alternatives are described in EB-2020-0091, Decision and Order, Section 7

[4] Per the IRP Framework (EB-2020-0091, Appendix A, p.4), Facility Alternative is "synonymous with a traditional or conventional facility project"

[5] EB-2020-0091, Decision and Order, p.27-28

a summation of the stakeholder engagement activities undertaken in 2021 see Section 4: Stakeholder and Indigenous Engagement Update.

Forecasting and Planning

Enbridge Gas regularly updates its long-term peak demand forecast and AMP (both comprehensive and limited updates depending upon timing and purpose). The objective of peak demand forecasting, and planning is to amass data, input, and insights to identify potential future system needs and constraints as well as their magnitude and timing. Early identification of future system needs and constraints is critical as the Company is obligated to reliably serve the firm contracted peak period demands of its customers.

A comprehensive discussion of Enbridge Gas' forecast and planning processes and any changes that have been made as a result of the establishment and implementation of the Framework will be filed in the Company's 2024 Rate Rebasing application in fall of 2022.

Need Identification

Following the completion of the forecasting process, Enbridge Gas compares the future forecast to the capacities of its existing facilities. A new system need/constraint is identified when Enbridge Gas determines that its current facilities cannot balance the new peak demand forecast with existing system facilities safely and reliably. When a constraint is initially identified, Enbridge Gas will verify its model with existing actual physical data, including pressure and temperature compensated consumption or flow, to ensure that the constraint is properly forecasted.

Baseline Facility Setting

Following the identification of a system need, Enbridge Gas develops the baseline facility that is required to meet the system need, absent any non-facility or IRPAs. It is necessary to understand this baseline facility as early as possible, as it provides a helpful point of comparison for other alternatives including IRPAs.

Binary Screening

Following the identification of a system need, Enbridge Gas will review the need relative to the Binary Screening Criteria established by the OEB in the Framework. If the system need passes Binary Screening, Enbridge Gas will then review and assess IRPAs or combinations of IRPAs that could meet the capacity requirements of the system need.

Binary Screening includes:

- "**Emergent Safety Issues**: If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and Enbridge Gas's broader transmission and distribution systems. Longer-term safety related system constraints/needs may be appropriate for an IRP Plan and should be considered on a case-by-case basis.

- **Timing**: If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.
- **Customer-Specific Builds**: If an identified system need has been underpinned by a specific customer's (or group of customers') clear request for a facility project and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required.
- **Community Expansion and Economic Development**: If a facility project has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required.
- **Pipeline Replacement and Relocation Projects**: If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than the minimum project cost that would necessitate a Leave to Construct approval [$2 million], then an IRP evaluation is not required."[6]

IRPA Technical Feasibility Assessment

For all system needs that pass Binary Screening, Enbridge Gas will assess which IRPAs could technically be used to defer, avoid or reduce the need/constraint relative to facility infrastructure. In other words, Enbridge Gas will ensure that the IRPA can serve the identified need prior to evaluating the IRPA on an economic basis.

Economic Evaluation

Enbridge Gas will test and compare the technical feasibility of both the baseline facility and any IRPAs on an economic basis using the OEB-approved DCF+ cost test. In the Decision, the OEB determined that Enbridge Gas has "some discretion in selecting an alternative to meet a system need that does not have the highest score on phase 1 of the DCF+ test, as there may be considerations or factors that are important in phase 2 and 3 or are difficult to quantify."[7] The IRPA, or combination of IRPAs, that can technically and economically meet the system need and satisfy the Framework's Guiding Principles, will be incorporated into the AMP for inclusion into its broader planning activities, stakeholder touchpoints and for implementation at the appropriate time.

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[6] EB-2020-0091, Decision and Order, p.47-49

[7] IBID, p.56

Project Development

Following the identification of IRPAs and the inclusion in the AMP, Enbridge Gas will begin work to develop and subsequently file an IRP Plan application and supporting evidence with the OEB for approval (where appropriate). Enbridge Gas will ensure that all details related to IRPAs and the underlying system needs that they are intended to address will be fully refined in this step and will continue to monitor the need as part of its planning activities until such time that the project is implemented.

IRPA Project Implementation

Enbridge Gas' IRP Plan applications will:

- detail anticipated savings or peak period impacts (on an hourly basis for distribution system assets and on a daily basis for transmission and storage system assets) together with the costs and ownership/operationalization arrangements proposed for IRPA investments;
- seek approval to spend and subsequently recover costs associated with investing in an IRPA(s);
- include additional applicable details for IRPAs such as design, administration, implementation, monitoring and reporting.

As is the case with traditional applications to the OEB seeking an Order of the Board for Leave to Construct facilities LTC applications, Enbridge Gas intends to consult with impacted landowners (where applicable), municipal governments, First Nations, Indigenous groups, and other affected stakeholders prior to filing its IRP Plan application with the OEB.

Monitoring and Reporting

Following implementation of approved IRPAs, the Company will carefully monitor their effectiveness in meeting the identified system need to ensure system constraints are being sufficiently resolved. Enbridge Gas will provide an annual report of IRPA effectiveness to the OEB as part of either its annual Rates application or Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, or as otherwise directed by the OEB. If any IRPA is not meeting the identified system need for which it was implemented, Enbridge Gas will propose corrective action in its report which may include, but not be limited to, proposals to implement additional IRPAs or new facilities.

3. IRP Pilot Projects

The OEB Directed Enbridge Gas to "select and deploy"[8] two IRP pilot projects by the end of 2022.

[8] EB-2020-0091, Decision and Order, p.94

The concept of developing and implementing two IRP pilots received universal support during the IRP proceeding.[9] Parties recognized that these IRP pilots would be an effective approach to better understand and evaluate how IRP can be implemented to avoid, delay or reduce facility projects required to meet the identified need.

The Technical Working Group was created to, among other matters, provide input and insight into the selection and development of the IRP pilots.

At the time of writing this Report the specific pilot projects and associated IRPAs have not been determined.

Enbridge Gas plans to file the two IRP pilot applications by December 31, 2022 for OEB review and implementation based on the following schedule:

June – August 2022	Review potential IRP Pilot projects
September	Select two pilot projects
September - December 2022	Develop IRP pilot evidence and applications
January – April 2023	OEB Procedural process
May 2023	IRP pilot project implementation

4. IRP Stakeholder and Indigenous Engagement Update

As part of the Decision in the IRP Framework proceeding "the OEB has determined that the components of Enbridge Gas's proposed Stakeholder Engagement Process will provide valuable input into Enbridge Gas's IRP activities and shall be incorporated in the IRP Framework. The OEB also directs the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholdering efforts."[10]

IRP Website

In December 2021, an Enbridge Gas IRP website went live.[11] This is the initial phase of the website and allows for individuals to identify which regions are of interest and to register for any stakeholder engagement that will occur within the regions(s) of interest. Individuals are welcome to register for as many regional engagement activities as they feel appropriate. By registering their emails,

[9] EB-2020-0091, Decision and Order, p.90
[10] IBID, p. 66
[11] https://www.enbridgegas.com/sustainability/regional-planning-engagement

individuals give permission to receive emails from Enbridge Gas in the future thus meeting the requirements of Canada's Anti-Spam Legislation (CASL).

The next phase of the website design is underway. This next phase will be available when a pilot project or IRP Plan is developed, and it will include additional regional functionality. The next phase will also allow interested individuals to sign up for webinars, in-person engagements, and to receive information about any presentations and/or responses to stakeholder feedback that is posted. It is anticipated that the second phase of the website design will be available prior to the launch of the first pilot project or IRP Plan.

Enbridge Gas has also implemented an internal working group that includes representation from Enbridge Gas' Municipal, Stakeholder and Community Engagement Group, Community and Indigenous Engagement and the IRP group to ensure that the internal resourcing and IT infrastructure developed to conduct, gather, and respond to the ongoing stakeholder engagement efforts in support of IRP will be sufficient to inform future planning efforts. This internal working group brings extensive stakeholder engagement experience and insight to the future IRP Stakeholder engagement plans. Enbridge Gas' various stakeholder engagement groups support efficient project execution with engagement activities in the field with project-area residents, local governments, and local organizations, in support of project objectives and business goals. They also regularly engage with key partners, including local municipal officials, business leaders, key landowners, emergency responders, and non-government organizations. Enbridge Gas anticipates engagement with Indigenous groups to commence in 2022 as IRP Plans are developed.

5. IRP Plan Update

Enbridge Gas has not developed or filed any IRP Plans with the OEB that can be reported at this time. Please see Appendix B for a list of projects that Enbridge Gas has completed the binary screening process following the OEB's IRP Decision.

6. Asset Management Plan (AMP) Update

The IRP Decision indicated that "for this first-generation IRP Framework, the OEB finds the process proposed by Enbridge Gas to identify system constraints or needs is acceptable. Recording potential system needs/constraints up to ten years in the future in the AMP will allow time for a detailed examination of IRPAs. The OEB agrees with Enbridge Gas's proposal that the first version of the AMP reflecting this updated process be filed in Fall 2022."[12]

[12] EB-2020-0091, Decision and Order, p.42

Enbridge Gas will file the 2023-2032 AMP in Fall 2022 with the 2024 Rate Rebasing application. The AMP will include the binary screening results for all facility projects, greater than $2 million, as noted in the IRP Assessment process description above. In addition, the AMP will include IRP assessment information for the projects, including IRPAs, where possible.

7. Integrated Resource Planning Alternatives Update

Discussion during the IRP regulatory proceeding included the request by some parties to have available a listing or menu of IRPAs being considered by Enbridge Gas. The OEB concluded that a "document on best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report."[13]

Appendix C lists the preliminary IRPAs and includes information on these specific IRPAs as suggested by OEB Staff including "types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions."[14] Enbridge Gas recognizes that this IRPA information is preliminary and will become more refined over time as the Company becomes more familiar with the actual impacts of these IRPAs on system peak demands and with the inclusion of more granular meter reading through an Automated Metering Infrastructure (AMI) application. Enbridge Gas also anticipates that the IRP pilot projects will provide further information allowing for the refinement and updating of the impacts of some of the IRPAs listed.

8. Technical Working Group Summary

The OEB's July 22, 2021, Decision further instructed the OEB to establish an IRP Technical Working Group (TWG) led by OEB staff, to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework.

The inaugural meeting for the IRP TWG was held on Tuesday January 18, 2022. Any updates or summaries of IRP TWG meetings held in 2022 will be included in and reported on in the 2022 IRP Annual Report. All documents and presentations with respect to the IRP Technical working group can be found on the OEB web site under proceeding EB-2021-0246.[15]

The Report of the Technical Working Group is included as Appendix D.

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[13] EB-2020-0091, Decision and Order, p.36
[14] IBID, p.34
[15] https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/natural-gas-integrated-resource

9. Interruptible Rates Update

The use of interruptible rates as an IRPA was reviewed as part of the IRP Framework proceeding. The discussion centered around a few key issues: "Customers on interruptible rates pay a lower rate in exchange for the ability of Enbridge Gas to curtail delivery if capacity is not available on the system. Interruptible volumes are not included in Enbridge Gas's design day assumptions. Therefore, increased use of interruptible rates could potentially reduce the amount of firm peak demand Enbridge Gas is obligated to serve, helping address a system need. For this reason, Enbridge Gas indicated that it does consider interruptible rates to be a type of IRPA. Enbridge Gas already offers interruptible rates to its Contract Rate customers (larger commercial, institutional and industrial customers). However, Enbridge Gas noted that customers have been moving away from interruptible rates as they value certainty of supply over cost reduction."[16]

In response Enbridge Gas indicated that it would "investigate the drivers for recent declines in the use of interruptible services and could potentially file revised interruptible and firm seasonal services/rates to make them more attractive to customers as part of its 2024 rebasing application."[17]

The OEB determined that "the impact of interruptible rates to meet a system need/constraint should be considered in an IRP Plan in combination with demand-side or supply-side alternatives."[18]

Enbridge Gas will file an interruptible rates study as part of its Rate Rebasing application in fall of 2022.

10. DCF+ Review

As part of the IRP Framework Decision the OEB found that "the OEB accepts the categories of benefits and costs proposed by Enbridge Gas for the three phases of the DCF+ test (shown in Table 2) for the use of this test in the IRP Framework. The OEB recognizes that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRPAs and clarify how these costs and benefits should be considered within the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP."[19]

The OEB further recognized that "this test could be improved to better list and define the costs and benefits of facility projects and IRP Alternatives and clarify how these costs and benefits should be considered within the test. Enbridge Gas is expected to study improvements to the Discounted Cash Flow-plus test for IRP, in consultation with the IRP Technical Working Group that will be established

[16] EB-2020-0091, Decision and Order, p,30
[17] IBID, p. 30-31
[18] IBID, p.35
[19] IBID, p.56-57

as part of the IRP Framework and using IRP pilot projects as a testing ground. Enbridge Gas shall file an enhanced Discounted Cash Flow-plus test for approval as part of the first non-pilot IRP Plan."[20]

Enbridge Gas has begun the process of reviewing the DCF+ test approved by the OEB. Enbridge Gas will consult with the Technical Working Group on any proposed enhancements to the DCF+ test prior to filing this cost benefit analysis with the first IRP non-pilot application.

[20] EB-2020-0091, Decision and Order, p. 5-6

Appendix A: OEB IRP Direction

The table below provides Enbridge Gas' progress with respect to meeting the Directions as ordered by the OEB in the IRP Decision.

Direction Item	Reference in the Decision	Direction	Status
Interruptible rates	Section 7 p.35	The OEB directs Enbridge Gas to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service.	In progress – will be included with Enbridge Gas Rebasing Application (2023-2032)
Documentation of demand side IRPAs	Section 7 p.36	The OEB concludes that a document on best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report. The OEB agrees with Enbridge Gas that supply-side alternatives require case-by-case examination and therefore are not required to be included in the listing.	Completed – preliminary list
Asset Management Plan	Section 8 p.42	The OEB directs that the AMP include information about Enbridge Gas' system needs. This includes providing the status of consideration of IRP Plans in regard to meeting system needs, the result of the binary screening, and details on the evaluation.	In progress – will be filed with the Enbridge Gas Rebasing Application
DCF+ test enhancement	Section 8 p.56-57	The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP and, as applicable, file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.	In progress
IRP Website	Section 10 p.66	The OEB also directs the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholder engagement efforts.	Phase 1 – Completed Phase 2 – In progress

Technical Working Group	Section 10 p.67	Establishment of a TWG with the OEB directing that membership should include Enbridge Gas, OEB staff, independent experts, and experienced non-utility stakeholders	Completed
IRP Deferral accounts	Section 15 p.87	The OEB directs Enbridge Gas to prepare a Draft Accounting Order for the two IRP Costs deferral accounts, consistent with the direction in this decision.	Completed

Appendix B: Binary Screening Results

Appendix B: Binary Screening Results for Projects Filed							
OEB Proceeding Docket	**Project Name**	**Customer Specific Build**	**Timing**	**Pipeline Replacement >$2M**	**Emergent Safety Issue**	**Community Expansion & Economic Development**	**Binary Pass or Fail**
EB-2022-0111	Bobcaygeon Community Expansion Project					Fail	Fail
EB-2022-0086	Dawn to Corunna Replacement Project		Fail				Fail
EB-2022-0088	Haldimand Shores Community Expansion Project					Fail	Fail
EB-2022-0003	NPS 20 Waterfront Relocation Project		Fail				Fail
EB-2020-0293	St. Laurent Ottawa North Replacement Project		Fail				Fail
EB-2021-0205	Greenstone Pipeline Project	Fail					Fail
EB-2021-0248	Coveny and Kimball-Colinville Well Drilling Project		Fail				Fail

Appendix C: Integrated Resource Planning Alternatives

Integrated Resource Planning Demand-Side Alternatives – Best Available Information

As per the IRP Decision, the IRP Annual Report is to include "a summary of best available information on demand-side IRPAs, including types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions".[21]

Demand-side IRPAs

IRPA Name	Enhanced Targeted Energy Efficiency (ETEE)
ETEE IRPA Overview	
Enhanced targeted energy efficiency (ETEE) programs focus on achieving necessary reductions in a specific geographical area to reduce peak period system demands. The mix of offerings and measures utilized in an ETEE program is dependent upon the scope of the facility investment project under consideration, customer characteristics in the specific project service area, past demand side management DSM participation etc. ETEE programs could include refining existing broad-based DSM offerings through enhanced incentives and targeted marketing or introducing new geo-targeted programs not offered through broad-based DSM. Broad-based DSM programs have been delivered throughout the Enbridge Gas service areas since 1993. The 2023-2027 DSM Plan (EB-2021-0002) is currently under consideration of the OEB to guide broad-based DSM programming over that time frame. As defined by the Ontario Energy Board in their DSM Letter, the objective of broad-based DSM is "assisting customers in making their homes and businesses more efficient in order to help better manage their energy bills".[22] Separately, Enbridge Gas proposes to undertake IRP pilots to review and understand the potential impacts of energy efficiency programs on peak period system demands within a geo-targeted area, and whether the impacts are significant enough to be considered an infrastructure alternative. Potential ETEE measures include those space heating equipment, water heating equipment and building envelope upgrades that could impact peak.	

21 The IRP Alternatives do not include electricity-based alternatives per the OEB's EB-2020-0091 Decision where it stated "The OEB has concluded that as part of this first-generation IRP Framework, it is not appropriate to provide funding to Enbridge Gas for electricity IRP Alternatives." p.4

22 EB-2019-0003, OEB Letter Post-2020 Natural Gas Demand Side Management Framework (December 1, 2020), p. 2.

IRPA Peak Impacts
Forecast peak impacts will be estimated on a case-by-case basis depending on the ETEE program. Enbridge Gas Inc. (EGI) worked with Posterity Group to build an end-use model of its service territory with the 2019 Achievable Potential Study (APS) being the starting point for the model creation. First, a mirror model of the APS was created and then several adjustments were made to better reflect EGI's knowledge and experience of the Ontario DSM market, EGI's current TRM assumptions and known changes to applicable standards. Then Posterity Group worked with EGI to develop peak factors which were added to the model so that enhanced targeted energy efficiency peak hour impacts estimates could be developed for each region, sector, segment and end use. Posterity Group and EGI plan to continue to evolve this model by refining assumptions and assessment methodologies to refine and improve forecasting of peak hourly flow reduction potential.
IRPA Cost Details
Costs will be determined on a case-by-case basis depending on the ETEE program. The Posterity model described above also included cost assumptions for ETEE programs. Posterity Group and EGI plan to continue to evolve this model by refining assumptions and assessment methodologies so it can be used to assess project specific costs for an ETEE program.
EGI Deployment Strategy
Which energy efficiency measures are chosen and what ETEE deployment strategy is undertaken will be dependent upon the scope of the facility investment project under consideration, customer characteristics in the specific project service area, past DSM participation etc. An IRP ETEE pilot project would provide insights that could guide the deployment strategy of a future IRP ETEE program, including to what degree Automated Metering Infrastructure (AMI) may be required to inform the objectives of the pilot.
Learnings from Pilot Projects/Other Jurisdictions
Enbridge Gas has engaged Guidehouse to undertake a jurisdictional review of ETEE (Enhanced Targeted Energy Efficiency) and DR (demand response) gas pilots implemented for the objective to defer or avoid infrastructure. Findings from the review are anticipated to inform potential pilots for natural gas IRP implementation. Enbridge Gas filed a Geo-Target Demand Side Management Case Study in EB-2020-0091 at Exhibit C, Appendix A. The objectives of the case study were:

1. Assessment of the impacts of geo-targeted DSM programs on reducing peak hour demand.
2. Assessment of the costs of geo-targeted DSM program implementation.

The results from this case study only illustrate the impacts geo-targeted DSM had on the town of Ingleside and although informative and directional, the results cannot be generally applied due to the specific nature of customer composition.

IRPA Name	Demand Response (DR)

IRPA Overview

Natural Gas Demand Response aims to reduce demand by natural gas customers during peak periods. For residential and commercial customers, this is usually in the form of heating demand reduction via thermostat control or water heater temperature settings. For contract customers, this can be done through leveraging Interruptible Rates.

IRPA Peak Impacts

Peak impacts will be determined on a case-by-case basis depending on the DR program.

IRPA Cost Details

DR IRPA costs will be determined on a case-by-case basis depending on the DR program.

EGI Deployment Strategy

The deployment strategy will be determined on a case-by-case basis depending on the DR program. An IRP Demand Response pilot project would provide insights that could guide the deployment strategy of a future Demand Response program, including to what degree Automated Metering Infrastructure (AMI) may be required to inform the objectives of the pilot.

Learnings from Pilot Projects/Other Jurisdictions

Enbridge Gas has engaged Guidehouse to undertake a jurisdictional review of ETEE (Enhanced Targeted Energy Efficiency) and DR (demand response) gas pilots implemented for the objective to defer or avoid infrastructure. Findings from the review are anticipated to inform potential pilots for natural gas IRP implementation.

Appendix D: Technical Working Group Report

Review of Enbridge Gas Inc. 2021 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities

From: Integrated Resource Planning Technical Working Group

June 9, 2022

Contents

1. Introduction

An Integrated Resource Planning (IRP) Framework for Enbridge Gas was established by the OEB through its *July 22, 2021 Decision and Order* (the IRP Decision). The IRP Decision directed the OEB to establish an IRP Technical Working Group (Working Group) and required a report from the Working Group to the OEB (Working Group report) to be filed in the same proceeding in which Enbridge Gas's annual IRP report is filed. The IRP Decision indicated that the Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Working Group, and may also describe other activities undertaken by the Working Group in the previous year.

This report has been prepared by OEB staff with input from all Working Group members, and approved by all Working Group members, as an accurate summary of the Working Group's activities.[1] Where views expressed in the report do not reflect the views of all members, this is clearly indicated.

2. Establishment and Initiation of Working Group

The IRP Decision instructed the OEB to establish a Working Group led by OEB staff, to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework.

The IRP Decision further required the OEB to establish a terms of reference and select the membership for the Working Group. On October 19, 2021, the OEB issued a *letter* seeking nominations from individuals interested in participating on the Technical Working Group as non-utility members. The OEB selected seven non-utility members from the twenty nominations received, and announced the establishment and initial membership of the Working Group in a *letter* issued December 6, 2021. In addition to non-utility members, the Working Group includes

[1] The IRP Technical Working Group includes observers from the Independent Electricity System Operator and EPCOR Natural Gas LP. As noted in the Working Group's Terms of Reference, any materials authored by the IRP Working Group (including this report) should not be considered to represent the views of Working Group observers, or their organizations.

representatives from the OEB and Enbridge Gas, and observers from the Independent Electricity System Operator and EPCOR Natural Gas LP.

The current membership of the Working Group is shown below.

Table 1: IRP Working Group Membership

Name	Role
Michael Parkes	OEB staff representative (Working Group chair)
Stephanie Cheng	OEB staff representative
Chris Ripley	Enbridge Gas representative
Whitney Wong (replacing Amrit Kuner)	Enbridge Gas representative
Amber Crawford, Association of Municipalities of Ontario	Non-utility member
John Dikeos, ICF Consulting Canada Inc.	Non-utility member
Tamara Kuiken, DNV Inc.	Non-utility member
Cameron Leitch, EnWave Energy Corporation	Non-utility member
Chris Neme, Energy Futures Group	Non-utility member
Dwayne Quinn, DR Quinn & Associates Ltd.	Non-utility member
Jay Shepherd, Shepherd Rubenstein Professional Corporation	Non-utility member
Kenneth Poon, EPCOR Natural Gas LP	Observer
Steven Norrie, Independent Electricity System Operator	Observer

The inaugural meeting of the Working Group was held on January 18, 2022. Meetings have subsequently been held on a monthly basis, with five meetings completed as of the date of this report.

Meeting notes and meeting materials for IRP Working Group meetings are published on the OEB's website following meetings to allow stakeholders to follow the Working Group's progress.[2] These materials can be found at: *https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/natural-gas-integrated-resource.*

As required by the IRP Decision, a draft terms of reference for the Working Group was developed by OEB staff. Following review and input from Working Group members at the initial meeting, a final terms of reference was issued by the OEB on February 17, 2022.

[2] Meeting materials are typically posted online shortly after the meeting. Meeting notes are not typically posted until after the following meeting, to allow for members to review draft notes and identify any omissions or inaccuracies.

3. Review of Enbridge Gas's Annual IRP Report and Comments on Implementation of the IRP Framework

The IRP Decision notes that the Working Group is expected to review a draft of Enbridge Gas's annual IRP report, with the review coordinated by OEB staff, and that Enbridge Gas should provide a draft of the annual IRP report to the Working Group far enough in advance of its planned filing to the OEB to allow the Working Group time to review and comment. The IRP Decision also indicates that the Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Working Group.

The Working Group's review took the following steps:

Enbridge Gas

Provided a draft of its 2021 annual IRP report to the Working Group for Review

This draft included the appendix "Integrated Resource Planning Demand-Side Alternatives – Best Available Information of IRPAs".

STEP 2

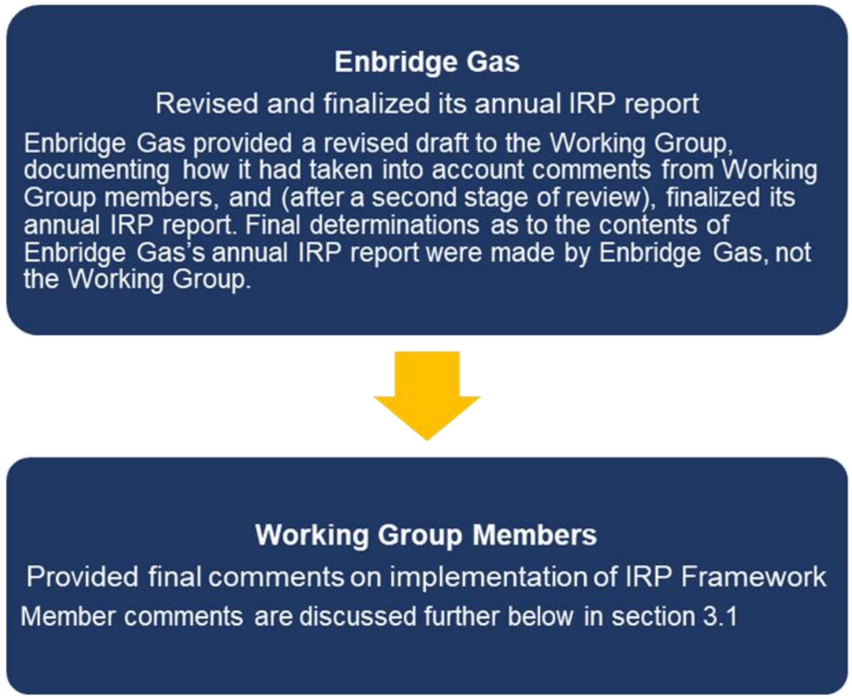
Working Group Members

Provided suggested edits and comments/clarifying questions

Member comments were generally aimed at ensuring that Enbridge Gas's annual IRP report accurately describes what Enbridge Gas has done and is doing regarding IRP, and includes the information required by the IRP decision. Members also suggested opportunities to improve the usefulness of the contents of the annual IRP report.

STEP 3

STEP 4



3.1. Working Group Comments on Implementation of the IRP Framework

All Working Group members (with the exception of observers) were asked the following question:

Question: Having reviewed Enbridge Gas's final annual IRP report's description of Enbridge's IRP activities in the previous year and having also participated on the IRP Working Group, do you have any comments or concerns with the implementation of the IRP Framework to date?

To varying degrees, all non-Enbridge Gas Working Group members expressed some concerns. These concerns relate primarily to: (1) the pace of Enbridge Gas's efforts to implement the IRP Framework since the IRP Decision in July 2021; and (2) the ability of the Working Group to make progress on its identified priorities (discussed in chapter 4 of this report) and meaningfully contribute to Enbridge Gas's IRP implementation, due in part to Enbridge Gas's determinations regarding the topics and level of detail that it has brought forward to the Working Group to date. More specifics are provided in the comments from individual members in Table 2, and the comments of Enbridge Gas Working Group members follow in Table 3.

Several members (including Enbridge Gas representatives) noted that more frequent meetings or focused subgroups may help advance progress on IRP implementation. The Working Group has agreed to add a second monthly meeting, with a subgroup focusing on the discounted cash flow-plus (DCF+) test, beginning in July 2022.

Table 2: Individual Comments of IRP Working Group Members

Working Group Member	Comments (optional)
Amber Crawford (non-utility member)	Since the Decision and Order was published on July 22, 2021, Enbridge Gas and OEB jointly created the nomination for membership of the IRP Technical Working Group. There have been five meetings held in 2022, and the following observations can be made thus far: **Little Progress Made on IRP Pilot Projects:** According to the Decision and Order, “the OEB expects that the [two] IRP pilot projects will be selected and deployed by the end of 2022.” (p.24). Meetings to date have discussed pilots at a very high-level, and have not yet seen substantive materials that would help the IRP Technical Working Group provide input on. While this may be in part due to Enbridge’s Asset Management Plan being developed this year, the criteria and potential choices should be further along to meet Enbridge’s deadline. **Lack of Transparency and Reliance on 2024 Rate Rebasing:** When asked to see data pertaining to pilots, the DCF+ test, binary screening results, best practices in other jurisdictions, or Enbridge’s Asset Management Plan, it has often been denied or mentioned it will be part of the 2024 Rate Rebasing in the Fall. Enbridges view that these topics are better addressed through testing of the evidence within the rebasing application. If this group is to provide input and expertise, it is incumbent on Enbridge to provide those details as otherwise, the consultation will not be meaningful. **Minimal Information in Annual IRP Report:** As a function of the slow progress in 2021, the Annual IRP Report fails to include details on key sections that would have been helpful and set up the 2022 year better (e.g. Sections 2, 6, 9). The Working Group’s review has been quite limited and question whether input to date has had a meaningful impact on Enbridge’s annual IRP report.

John Dikeos (non-utility member)	I agree with many of the comments from other Working Group members that Enbridge's progress on identifying and screening potential IRPA pilots and updating its DCF+ cost-effectiveness approach has been relatively slow. There was very limited progress on these items in advance of the first Working Group meeting in January 2022 and progress since has been slow as well. To date, this has limited the Working Group's ability to provide more meaningful contributions to the future of IRPA planning in Ontario. I noted the following additional items based on my review of Enbridge's final 2021 IRP Annual Report: **Evolution of binary screening criteria:** Enbridge has included high-level details regarding its binary screening criteria for IRPAs. Although the criteria appear to be reasonable at this stage given the current knowledge and experience with IRPAs, Enbridge should be encouraged to revisit and evolve the criteria on an ongoing basis. For example, the Timing criteria should likely be condensed as Enbridge gains additional knowledge and experience with demand-side IRPAs. **Interruptible rates:** Enbridge notes that it is completing a study on interruptible rates, which will be filed as part of its rebasing application in fall 2022. As part of this study, Enbridge should investigate alternative and/or enhanced approaches to interruptible rates, such as the pilot projects that are being run by some utilities in New York (e.g., ConEd).
Tamara Kuiken (non-utility member)	I agree with many of the comments made by other reviewers, including those related to the lack of progress made on IRP pilots, the lack of progress made on improving the DCF+ test, communication about IRP elements delayed until the rebasing application, all initial IRPAs failing the binary test, and the perfunctory IRP Report. In my opinion, Enbridge shows little urgency toward advancing the IRP process, despite their commitment to deploy pilots before the end of 2022. The initial stated reason was a desire to engage with the TWG prior to making commitments; however, the lack of progress since the TWG was initiated suggests that other barriers exist.
Cameron Leitch (non-utility member)	From the definitions within the IRP Framework, this process is meant to address system needs by considering alternatives to conventional facility projects. At the core of this process is clarity on the determination of system needs, and without

	insight into this determination (outside of the future AMP submission), it is difficult for the Working Group to provide meaningful feedback. Comments by other members of the Working Group are insightful, and my repetition of them will not provide added value to the reader.
Chris Neme (non-utility member)	While there have been some good initial discussions, and the tone of those discussions has been appropriately congenial and open-minded, I have several concerns about the effectiveness of the working group (WG) thus far. The most important are as follows: 1. **Input on key IRP issues related to the Company's next Asset Management Plan (AMP) and rate-basing application has essentially been taken off the table**. Among those key issues are (A) the Company's approach to load forecasting in light of Canada's energy transition commitment, fast-increasing carbon taxes and the potential for the Company to partially control demand growth through limitations on new connections; (B) how binary screening criteria are to be assessed/applied, including the how the timing of needs is to be determined (given the binary screening criterion that says alternatives to traditional infrastructure investments should not be considered if the system need is within three years); and (C) how risks of stranded assets are to be addressed (e.g. if load grows in the near term but then declines as electrification takes hold). Had the Company been willing to engage on these issues prior to its filing in the Fall, some progress eliminating issues – or at least surfacing key issues and ensuring that the filing provided data/info likely to be important – could have been made, saving the Board time and making the filing a better product. These kind of collaborative working groups – speaking here to a groups addressing a range of topics, not just IRP – routinely provide such construction feedback in other jurisdictions. 2. **Little progress on pilots – and therefore likely failure to begin deploy IRPAs as part of pilots before the end of 2022**. This is particularly concerning given that it is essentially one of just two issues that the WG has effectively prioritized for 2022. While I appreciate that the Company may not have wanted to get too far in planning for the pilots until the

	WG had formed, it still could have done a lot of groundwork identifying potential projects/locations for pilots (e.g. maybe developing an initial short list of 10-12) so that we could have jumped right into selection once the WG had talked through priorities. 3. **No progress on the revisions to the DCF+ cost-effectiveness test**. This also has relevance to the Company's upcoming AMP and rate-basing application, so it would have been ideal to have worked through some issues in greater detail in the first half of 2022. 4. **Enbridge's first IRP Report is largely perfunctory, with little useful information**. This seems a function of two related things: (A) no IRPAs have been identified yet for deployment; and (B) the Company has decided that all planning related to IRPA consideration will be addressed in its AMP and rate-basing application. As stated above, the Company's decision to not bring its draft approach to applying the IRP framework to its AMP is an unfortunate missed opportunity. Hopefully next year's IRP report will be more substantive. Note that greater progress on the items above may have been hindered by having just one meeting a month among a dozen or more people. That might suggest the need for some sub-groups focused on particular topics (e.g. cost-effectiveness test) and perhaps with fewer people involved to meet more often. Those subgroups could then report back draft recommendations for the full WG to consider. This model is being used very effectively, for example, by the Illinois Stakeholder Advisory Group (SAG) for energy efficiency. They have full working group meetings quarterly (used to be monthly) but have numerous subcommittees (also with regular meetings) and working groups (more episodically meeting to address specific topics that have more time-sensitive needs). See www.ilsag.info.
Dwayne Quinn (non-utility member)	As the last non-utility member to comment, instead of "piling on" regarding the lack of opportunity for the IRP WG to understand the lack of progress by the utility or even the behind the scene processes, we will simply support contributions of each of the other non-utility members. I am concerned that the Enbridge comments seem to dismiss consensus comments by the group. I believe the reality lies in the fact that Enbridge has not advanced even one single

	concrete example of a potential pilot, which could have been used to allow input from the WG on process matters. The cumulative years of experience and aggregated intellectual capital of the committee is being wasted as we await something substantive to review and to initiate collaboration.
Jay Shepherd (non-utility member)	***Very Little Has Been Done To Date.*** This Report demonstrates that little was done from July 22 to December 31, 2021 to advance IRP in Ontario. The Report discloses that the following steps were taken in that 5+ month period: 1. A bare bones website was created (perhaps a day's work), in which the primary functionality is the ability of customers to indicate their interest in regional constraints and the related IRPAs. However, there are no regional constraints or IRPAs identified, and will not be until the end of 2022 at the earliest. Enbridge promises future enhancements to the website late in 2022 or early in 2023. 2. A committee of the stakeholder engagement folks at Enbridge has been created, but they will have nothing to do until late 2022, when constraints and potential IRPAs have been identified. Nothing else appears to have been done. No preliminary work was done on the pilots, or the DCF+ test, or best practices in other jurisdictions, etc. Or, if there was, none of it was brought to the attention of the IRP Working Group. ***Asset Management Plan – Refusal to Disclose.*** In parallel, Enbridge has moved forward with its 2024-2028 Asset Management Plan, but does not appear to have incorporated IRP into that process. Further, when asked to provide information to the IRP Working Group on the process of the AMP, and how it was influenced by IRP, Enbridge refused to do so. Members of the working group sought a draft of the AMP, which should be substantially finalized at this point, but that disclosure was refused. ***Load and Demand Forecast – Refusal to Disclose.*** Related to this, Enbridge has, in 2021 and 2022, been preparing its ten year load forecast for the AMP to be filed in the rebasing application, but has declined to share any information on that forecast with the IRP working group. It does not appear that Enbridge has taken any action so far to

	influence that forecast downward through, for example, longer term planning for, or forecasting of, IRPAs. ***Posterity Group Model – Refusal to Disclose.*** Another refusal from Enbridge was the request from the IRP working group to see the Posterity Group model that Enbridge plans to use to assess IRPAs. Enbridge will not provide that model unless compelled to do so by the OEB. ***Interruptible Rates Study – No Consultation with IRPWG.*** At the same time, Enbridge has proceeded (in 2022, not 2021) with an interruptible rates study as it relates to IRP, but has not brought any information on that study to the IRP working group, and apparently does not intend to do so. ***100% Fail Rate in Binary Screening.*** To date, Enbridge has used binary screening on seven projects, and all have failed, in most cases because of Enbridge's determination that the need must be met in under three years. One of these was the St. Laurent Phase 3 and 4 project, which the OEB determined in the EB-2020-0293 LTC application would not proceed at this time. It is not known yet whether the others that failed the screening can stand up to a similar independent review. No information on that binary screening has been provided to the IRP working group. ***Pilot Projects – Non-Compliance with OEB Direction.*** Enbridge also discloses in the attached Report that they will not comply with the OEB direction to "select and deploy" two IRP pilot projects by the end of 2022. They have unilaterally determined, without input from the IRP working group, that they will complete the "select" stage by the end of the year, but will not have the pilot projects "deployed" until the winter of 2023, rather than the winter of 2022. Against this contextual background, Enbridge has been adding to rate base at an average rate of $100 million of capital additions per month since the IRP Decision, and is continuing to do so. The inescapable conclusion from this Report, and from the actions of Enbridge to date, is that their strategy is a "slow walk" of IRP, consistent with their past resistance to the concept.

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<td>Mike Parkes/Stephanie Cheng (OEB staff representatives)</td>
<td>In OEB staff’s view, Enbridge Gas is taking the initial steps (as documented in Enbridge’s annual IRP report) to implement the IRP Framework in accordance with the OEB’s direction. This includes participating in good faith on the IRP Working Group. Implementation of the IRP Framework is still at a preliminary stage. At this time, OEB staff provides additional comments on three topics:

Slow start on IRP Pilots (section 3 of Enbridge Gas annual IRP report): The IRP Framework indicated that Enbridge Gas should develop and implement two IRP pilot projects, with the expectation that the pilot projects would be selected and deployed by the end of 2022.

Based on the description in the annual IRP report and the information that has been shared with the Working Group, the amount of preparatory work done by Enbridge Gas in the months following the IRP decision in July 2020 to lay the groundwork for these pilots (in advance of seeking input from the IRP Working Group) was very limited.

While OEB staff recognizes that this was in part because Enbridge Gas did not want to overly constrain pilot design prior to receiving input from the Working Group, the result is that it is unlikely that pilots will be deployed (if “deployed” is interpreted to include having received an OEB approval) by the end of 2022, which was the expectation of the IRP Decision. The consequence is that there will be a related delay in transferring learnings from the pilots into Enbridge Gas’s system planning decisions. It will be important for Enbridge Gas to make use of learnings from the pilots while they are still in-flight, to inform Enbridge Gas’s consideration of IRP alternatives in system planning.
Insufficient information base to compare IRP Alternatives Versus Facility Projects (sections 2,7, appendix B of Enbridge Gas annual IRP report): Under the IRP Framework, Enbridge will use a four-step IRP Assessment Process to determine the best approach to meeting system needs. Where such system needs pass an initial binary screening, Enbridge Gas is required to assess the technical and economic feasibility of IRP Alternatives in comparison with traditional facility solutions.

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	The level of detail in appendix B (*Integrated Resource Planning Demand-Side Alternatives – Best Available Information*) of Enbridge's initial annual IRP report regarding IRP Alternatives, including their cost and peak demand reduction potential, is generally insufficient to assist Enbridge Gas in completing this step of IRP assessment, and will need to be improved in future annual IRP reports. Information on IRP Alternatives will be informed and improved by the results of Enbridge Gas pilots. However, Enbridge Gas will need to conduct IRP assessments prior to completion of the pilots (e.g. for potential system needs identified in Enbridge's rebasing application). In OEB staff's view, Enbridge will need to supplement the information obtained from IRP pilots with other sources of information on the expected cost and peak demand reduction potential of IRP Alternatives (including results from other jurisdictions), to assist it in completing IRP Assessments (and to assist the OEB in reviewing Enbridge Gas's determinations). Otherwise, the risk is that no IRP Alternatives will advance past this stage of IRP Assessment for many years. • **Limited information and Working Group review of IRP elements of rebasing application (sections 2, 6, 9 of Enbridge Gas annual IRP report):** The OEB's review of Enbridge Gas's rebasing application (expected to be filed in November 2021) will have significant consequences for implementing the IRP Framework. Issues of particular importance noted briefly in the annual IRP report include: Enbridge Gas's updated asset management plan and its approach (and conclusions) regarding screening system needs for IRP alternatives and reporting on the status of such consideration (section 6), Enbridge Gas's approach to demand forecasting (section 2), and Enbridge Gas's approach to studying the potential for interruptible rates (section 9). In OEB staff's view, Enbridge Gas's approach to demand forecasting in light of the energy transition to lower-carbon energy sources will likely have significant implications for IRP and system planning, both regarding identification of system needs and the role of IRP Alternatives as potential solutions.

	These issues are only mentioned briefly in the annual IRP report, and the Working Group has not to date been provided with substantive details of how these topics will be addressed in Enbridge Gas's rebasing application, and has not commented on them. At this point in time, if any review by the Working Group occurs, it will likely be quite limited. Reasons for this include: these topics were not identified as a priority for the Working Group in the IRP Framework; Enbridge Gas's view that these topics are better addressed through testing of the evidence within the rebasing application; and views of some Working Group members that input at this stage is unlikely to have a meaningful impact on Enbridge Gas's application. The consequence is that these issues will be addressed in the rebasing application without significant prior input from the Working Group.

Table 3: Comments of Enbridge Gas IRP Working Group Members

Working Group Member	Comments (optional)
Chris Ripley/Whitney Wong (Enbridge Gas representatives)	Enbridge Gas has structured its comments to follow the Working Group Participant comments above. For context, Enbridge notes that the Working Group's focus, per the Terms of Reference and the OEB's IRP Decision, are three main issues: the IRP Annual Report, the DCF+ cost/benefit test and the IRP Pilots. Enbridge Gas does not agree with the negative tone of many of the Working Group Participant comments. Enbridge Gas has been working diligently on IRP implementation and engaging responsibly with the Working Group, in a manner consistent with the OEB's directions and expectations from the IRP Framework. As described below, Enbridge Gas expects that the pace of Working Group progress and activities will increase in the coming months. **Minimal Information in Annual IRP Report:** As noted above, the 2021 IRP Annual Report is reporting on 2021 activities and information. While progress has been made on the three main Working Group tasks; Annual Report, DCF+ and pilots the work has been largely completed in 2022 and will appear in the 2022 IRP Annual Report. In addition, in Enbridge's view there is a mismatch between the IRP Annual Report, which relates to 2021, before the Working Group held its first

	meeting, and the comments from the Working Group members on that Report, almost all of which relate to the experience of the Working Group in 2022. Over the next few months, the Working Group will discuss potential pilot projects and review Enbridge Gas' proposals for the DCF+ Test. **Little Progress Made on IRP Pilot Projects:** Enbridge does not agree with the Working Group comments suggesting Enbridge Gas made little effort on the IRP Pilots Projects. The OEB's IRP Decision stated "the OEB expects that the [two] IRP pilot projects will be selected and deployed by the end of 2022." (p.24). Enbridge acknowledges deployment by the end of 2022 is not possible, this is entirely due to the timing of Enbridge's demand forecast and planning processes being completed in Q2 of 2022. The 2023-2032 Asset Management Plan ("AMP"), generated in May 2022, identifies the needs on Enbridge's system. The pilot projects need to be, and will be, based on actual system needs that have been identified in Enbridge Gas' AMP. Enbridge Gas has included an updated IRP pilot schedule in its Annual Report. Enbridge Gas will bring 4-5 actual system needs for each of the two proposed IRP Pilots to the Working Group, including all relevant information to the need. Enbridge Gas will discuss the system needs brought forward with the Working Group, select two IRP Pilot projects and then prepare an application for the OEB's review and approval. In order to complete the IRP Pilot selection process quickly, Enbridge Gas proposed to increase the number of Working Group meetings from once per month to twice per month. **DCF+ Test:** Enbridge Gas engaged Guidehouse Consulting to conduct a review of the DCF+ test approved by the OEB in the IRP Decision. Enbridge Gas expects to receive the Guidehouse Final Report in June 2022 and will use the Guidehouse report in its review of the DCF+ test and in any proposed changes. Enbridge Gas will be communicating the Guidehouse Report and Enbridge Gas' proposed changes in the July IRP Working Group meeting. As discussed at the Working Group, a sub-group will be established to review the Guidehouse Report and Enbridge's associated proposed changes to the DCF+ Test. This review and discussion will happen prior to the cost test being applied to the IRP Pilot projects or an IRPA Plan.

	Lack of Transparency and Reliance on 2024 Rate Rebasing: Enbridge Gas is filing its 2024 Rebasing Application in Fall 2022 which will include a comprehensive review of Enbridge Gas' planning processes, the demand forecast and the Asset Management Plan. Enbridge Gas never understood the Working Group would provide input on the demand forecast process and the asset management requirements. The appropriate time to review Enbridge Gas' planning processes and the Asset Management Plan is in the Rebasing proceeding, not at the IRP Working Group. Enbridge Gas is holding a Rebasing Stakeholder meeting in June 2022 where Enbridge will provide information about the upcoming filing. Enbridge Gas notes there is no direction to review or provide the planning processes, demand forecast or the Asset Management Plan to the Working Group in the OEB's IRP decision or the IRP Working Group Terms of Reference **Posterity Model:** The Working Group have requested Enbridge Gas to provide the model used by Posterity Group to assess energy efficiency opportunities on Enbridge Gas' system. Enbridge Gas does not own the Posterity model and cannot provide it. Enbridge Gas will explain the model, how it is used and the inputs/outputs as it develops the IRP Pilots. **Interruptible Rates:** In its IRP Decision, the OEB ordered Enbridge Gas "to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service. This initiative is expected to help reduce peak demand, and the study should be filed as part of the next rate rebasing application". (p.35). Enbridge is completing this direction and it will be filed in the Rebasing Application. Enbridge Gas notes there is no direction to review the Interruptible Rates study with the Working Group in the OEB's IRP decision or the IRP Working Group Terms of Reference.

4. Description of Other Key Activities to Date

The Working Group's Terms of Reference confirmed the following items noted in the IRP Decision as the highest initial priorities for the Working Group (in addition to the review of Enbridge Gas's annual IRP report):

- **Consideration of IRP pilot projects to better understand how IRP can be implemented to avoid, delay or reduce facility projects.**

    - The IRP Framework indicated that Enbridge Gas is expected to develop and implement two IRP pilot projects. The pilots are expected to be an effective approach to understand and evaluate how IRP can be implemented to avoid, delay or reduce facility projects. The IRP Framework indicated that the OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022.

    - <u>Working Group activities:</u> The Working Group has had several discussions to provide input to Enbridge Gas on pilot design, focusing primarily on the pilot objectives, the criteria that will be used to select and prioritize pilots, and the types of IRP Alternatives should be a priority to test in the pilots. Enbridge Gas has proposed four potential pilots built on different types of IRP Alternatives: (1) enhanced targeted energy efficiency in combination with a bridging supply-side solution; (2) a peak shaving supply-side IRP Alternative using either compressed natural gas or liquefied natural gas; (3) a demand response program focused on general service customers' heating loads; and (4) a demand response/interruptible rates initiative focused on Enbridge Gas's larger contract customers. Enbridge Gas is also considering a geographical IRP pilot that may address multiple needs within a specific area and include a suite of IRP alternatives, potentially including demand-side and supply-side IRP alternatives, as well as considering enhanced inspection/integrity management measures. In the coming months, it is expected that Enbridge Gas will propose specific projects that match these potential pilots to real system needs identified in its Asset Management Plan, for Working Group review, prior to Enbridge Gas's final selection of pilots. Additional discussion and refinement of the pilot proposals will take place by the Working Group, prior to Enbridge Gas filing pilot applications to the

OEB for approval.

- **Enhancements or additional guidance in using the Discounted Cash Flow-plus economic evaluation methodology to assess and compare the costs and benefits of using either facility solutions or IRP alternatives to meet system needs.**

    - The IRP Framework established a three-phase discounted cash flow-plus (DCF+) test as the economic evaluation that will be used to compare the costs and benefits of different approaches to meeting system need (IRP alternatives, facility alternatives, or a combination). The OEB concluded that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRP Alternatives, and clarify how these costs and benefits should be considered within the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. Enbridge Gas was directed to study improvements to the DCF+ test, and encouraged to consult with the Working Group, and use the IRP pilot projects as a testing ground. Enbridge Gas was directed to file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.

    - Working Group activities: The Working Group has had several preliminary discussions on this topic. This included an analysis and *presentation* by Working Group member and cost-effectiveness expert Chris Neme, which made several proposals to improve or refine the DCF+ test, while remaining consistent with the OEB's guidance on this topic in the IRP Decision. Enbridge Gas is also planning to propose several refinements to the DCF+ test, but these have not yet been discussed with the Working Group. In the coming months, the Working Group plans further discussion, with the goal of agreeing on a preliminary approach to cost-effectiveness that can be used for the IRP Pilot applications. Additional work will be done as needed to address issues that were not completely resolved at the time of filing the pilot applications, and may include development of a supporting guidance document regarding use of the DCF+ test.

The Working Group has also discussed whether to give any consideration to the IRP-related aspects of Enbridge Gas's rebasing application, which would likely be contingent on the degree of information that Enbridge Gas will provide regarding its application. Enbridge Gas has recently indicated that it will bring forward information on one IRP issue that will be part of rebasing - Enbridge Gas's approach to interpreting the IRP Framework's criteria for screening system needs - for discussion at an upcoming Working Group meeting, and is considering whether other IRP-related aspects of the rebasing application, including the draft Asset Management Plan, can be discussed with the Working Group.

Other potential areas of work for the Working Group in the future may include addressing:

- Learnings from natural gas IRP in other jurisdictions
- Performance metrics for IRP
- Accounting treatment of IRP costs
- Treatment of stranded assets in system planning
- Other activities relevant to the IRP Framework, as identified by the Working Group or as directed by the OEB

The Working Group has not to date discussed these topics in any depth (with the exception of some consideration of IRP in other jurisdictions with regards to pilot proposals).

A draft Work Plan is maintained for the Working Group and updated on a regular basis, outlining workstreams and expected timing of key deliverables.